U. S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Carolina Power & Light (CP&L)
Facility:	Shearon Harris Nuclear Power Plant, Unit 1
Location:	5413 Shearon Harris Road New Hill, NC 27562
Dates:	March 30 - May 10, 1997
Inspectors:	J. Brady, Senior Resident Inspector D. Roberts, Resident Inspector J. Coley, Reactor Inspector (Sections M2.5, M2.6, and M2.7) P. Fillion, Reactor Inspector (Sections E1, E2, and E7) J. Lenahan, Reactor Inspector (Sections E1, E2, E7, and E8) G. MacDonald, Project Engineer (Section M1.3) W. Rankin, Senior Project Manager (Section R1) H. Whitener, Reactor Inspector (Sections M1.2 and M2.2) G. Wiseman, Reactor Inspector (Sections F1 through F8) R. Hall, General Engineer (Intern)
Approved by:	M. Shymlock, Chief, Projects Branch 4 Division of Reactor Projects

Enclosure 2

EXECUTIVE SUMMARY

Shearon Harris Nuclear Power Plant, Unit 1
NRC Inspection Report 50-400/97-04

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection; in addition, it includes the results of announced inspections by six regional specialists and a regional project engineer.

Operations

- Movement of fuel assemblies during refueling was conducted in an acceptable manner. The licensee made conservative decisions when problems arose while moving fuel assemblies, and the use of specialized equipment was beneficial (Section O1.2).

- A violation was cited for failing to comply with Technical Specification 3.0.4. Although the violation was licensee-identified, the licensee's initial corrective actions were inadequate (Section O1.3).

- Equipment operability, material condition, and housekeeping were acceptable in all cases observed by the inspectors. No substantive concerns were identified during plant walkdowns (Section O2.1).

- A violation with three examples of failure to properly implement corrective actions was identified. Two of the examples involved boron dilution events (Sections O4.1 and O4.2). Each dilution event represented failures of control room supervision to adequately supervise board operators and properly communicate expectations. Additionally, each event pointed out weaknesses in the management of reactivity manipulations. The third example involved ineffective corrective action for LER 96-013-01 as evidenced by recurrence of a Technical Specification 3.0.3 entry during chemical addition to the component cooling water system (Section O8.1).

Maintenance

- Maintenance personnel were knowledgeable of their assigned tasks, approved procedures were at the job and followed, work areas were controlled and instruments were calibrated (Section M1.1).

- Transportation of the Reactor Coolant Pump motor into containment was well executed. Load paths were evaluated and contingencies for potential damage to the Refueling Water Storage Tank were taken (Section M1.2).

- Inspection of Emergency Diesel Generator (EDG) overhaul met the requirements of plant procedures, the vendor manual, and the vendor service information memorandum regarding 10-year surveillance and maintenance activities. The EDG work activities were conducted in a professional manner by knowledgeable personnel. The engine/component inspections performed were thorough and identified problems were

conservatively resolved. Some discrepancies were noted regarding documentation of NDE inspections on EDG cylinder liners. (Section M1.3)

- Licensee activities involving the detection and recovery of foreign objects in the "A" Steam Generator were conducted in an acceptable manner. The licensee performed an adequate analysis of the cause of the foreign objects, and a review of the potential for foreign objects entering the other steam generators (Section M1.4).

- Surveillance procedure problems were observed in several tests during the refueling outage including the remote shutdown system test and the high head safety injection pump test (Sections M2.1, M2.2, and M2.3).

- A non-cited violation was identified for failing to establish and implement adequate procedures for using test equipment on the "A" emergency battery. The use of an improper jumper cable resulted in a small battery fire (Section M2.4).

- Ultrasonic examinations and interpretation/evaluation/acceptance of the reactor vessel ISI test results were conducted in a proficient manner by experienced and knowledgeable examiners (Section M2.5).

- Steam generator eddy current activities were well managed. Program and examination procedures were very good, knowledgeable/skillful vendor personnel were utilized, and state-of-the-art examination equipment was used (Section M2.6).

- The licensee's disposition of the containment liner thickness issue was resolved in a sound technical manner. Licensee ultrasonic examination personnel performing the containment liner thickness measurements were resourceful, skillful and very knowledgeable of the ultrasonic method (Section M2.7).

- An apparent violation was identified for an inadequate 10 CFR 50.59 safety evaluation which ultimately led to the removal of containment equipment hatch missile shield protection while it was required to remain installed during Mode 3 operations (Section M3.1).

Engineering

- The licensee's current design change control procedures complied with the requirements of 10 CFR 50.59, and 10 CFR 50, Appendix B, Criterion III (Section E1.1).

- A non-cited violation was identified for failure to implement the design verification requirements of 10 CFR 50, Appendix B, Criterion III for safety-related configuration change Engineering Service Requests completed between June 3, 1996, and February 11, 1997 (Section E1.1).

- Modifications packages reviewed were of good quality and complied with design control requirements (Sections E1.2 and E1.3).

- Plant engineers conducted a good indepth evaluation of the containment lines corrosion problem after it was identified by the inspectors (Section E1.4).

- The licenseee has established acceptable procedures for the review and evaluations of NRC information notices (Section E2.2).

- The licensee's self-assessments in engineering were adequate (Section E7.2).

- The Harris Engineering Support Section was proactive in support of the plant when emergent conditions were identified (Sections E2.1 and E2.3).

Plant Support

- The radiological controls program was being effectively implemented overall with good radiation control performance demonstrated during outage conditions (Section R1.1).

- One non-cited violation was identified for failure of radiation workers to promptly leave a work area when their electronic dosimeters alarmed (Section R1.2).

- One non-cited violation was identified for failure to tag and label radioactive material in accordance with procedure (Section R1.3).

- Contamination control was effective overall with personnel contamination events on a favorable reducing trend (Section R1.4).

- The ALARA program was effectively controlling total site dose to record lows for the site (Section R1.5).

- The licensee has been proactive in the resolution of the Thermo-Lag issue (Section F1.2).

- Good compliance with plant fire prevention procedures has resulted in a low incident of fire within the plant protected area (Section F1.3).

- There was not a significant corrective action maintenance backlog associated with the fire protection systems. The material condition of fire protection components was good (Section F2.1).

- A violation of Technical Specification 6.8.1.a was identified for failing to establish written procedures to verify the functional operability of the seismic fire protection check valves that provide fire protection and emergency service water system integrity following a Safe Shutdown Earthquake (Section F2.2).

- Implementation of the fire protection surveillance program has not been fully effective. As previously identified in licensee self assessments, the number of fire protection surveillance procedures being performed within their grace period continued to be excessive (Section F2.3).

- The fire protection program implementing procedures were good and met licensee and NRC requirements. The fire fighting pre-fire plans were satisfactory. Appropriate fire prevention controls were being applied to refueling outage activities (Section F3).

- The fire brigade organization and training met the requirements of the site procedures (Section F5).

- A 1997 assessment of the facility's fire protection program was comprehensive and was effective in identifying fire protection program performance deficiencies to management. Planned corrective actions in response to the audit issues were acceptable (Section F7).

Report Details

Summary of Plant Status

Unit 1 began this inspection period at 100 percent power. The unit was maintained at this power level until April 4, 1997, when operators reduced power in preparation for the refueling outage, RFO-7. Operators manually tripped the reactor and the unit entered Mode 3 (Hot Standby) on April 5. Mode 4 (Hot Shutdown) was entered on April 5 and operators continued to reduce reactor coolant system temperature, placing the plant in Mode 5 (Cold Shutdown) on April 6. The unit entered Mode 6 (reactor vessel head detensioned with fuel in the vessel) for refueling on April 16 and defueling of the reactor core was completed on April 23. The reactor vessel 10-year inspection was completed during the defueled period. Mode 6 was re-entered on May 6, and the unit remained there until May 14 when Mode 5 was entered (reactor vessel head fully tensioned with fuel in the vessel). The unit remained in Mode 5 for the remainder of the period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. These included reactor shutdown and plant cooldown activities conducted in accordance with procedures GP-006, Normal Plant Shutdown from Power Operation to Hot Standby (Mode 1 to Mode 3), Revision 13; and GP-007, Normal Plant Cooldown (Mode 3 to Mode 5), Revision 15.

The inspectors also observed all or portions of the following core alterations during the use of procedure GP-009, Refueling Cavity Fill, Refueling and Drain of the Refueling Cavity, Revision 13:

- Integrated Reactor Vessel Head removal and installation
- Removal and installation of the Upper Internals Package from the reactor vessel
- Removal and installation of the Lower Internals Package from the reactor vessel to facilitate the 10-year reactor vessel inspection.

In general, the conduct of plant operations was professional and safety-conscious. Technical specification requirements for equipment operability, instrument channel checks, and plant cooldown rates were adhered to for specific activities observed by the inspectors. Specific events and noteworthy observations covered by other procedures are detailed in the sections below.

01.2 Fuel Movement

a. Inspection Scope (60710)

The inspectors used Inspection Procedure 60710 to observe the refueling activities involving fuel assembly movement.

The inspectors observed all or portions of the following fuel handling procedures:

- FHP-014, Fuel and Insert Shuffle Sequence, Revision 12/1.
- FHP-020, Refueling Operations, Revision 13 and 13/1.
- FHP-025, HNP Insert Handling Operations, Revision 6.

b. Observations and Findings

The inspectors found the fuel movement performed under these activities to be professional and thorough. All work observed was performed with the procedures present and in active use. Operators were experienced and knowledgeable of their assigned tasks. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure. Foreign material exclusion areas were maintained as required.

The licensee had problems with three fuel assemblies. A leaking fuel rod in assembly (HA-50) was identified by using in-mast sipping, a technique used to detect the presence of certain radionuclides along the length of the fuel assembly. Assembly HA-50 was not scheduled to be reloaded in the core and was stored in the spent fuel pool. Assembly, HJ-48, did not indicate being fully latched to the fuel handling crane in the spent fuel handling building. This was caused by the indicator flag not remaining in the full up position when the assembly was lifted. After several attempts and troubleshooting, the licensee used an underwater camera to verify the assembly was latched before finally moving the fuel assembly in the fuel handling building. This assembly was subsequently reloaded in the core with no problems. Another assembly, HJ-57, had a thimble guide tube lodged in the instrument tube of the assembly. The licensee was able to remove the thimble guide tube using an underwater camera and consultation with fuel vendor representatives. Assembly, HJ-57, was ultimately reloaded in the core, but was placed in a location where insertion of a thimble guide tube was not necessary.

c. Conclusions

The inspectors concluded that licensee activities involving the movement of fuel assemblies were conducted in an acceptable manner. The licensee made conservative troubleshooting and contingency decisions when problems arose, and the use of specialized equipment was beneficial.

01.3 Prohibited Mode 6 Entry

a. Inspection Scope (71707)

On May 8, 1997 at 7:18 a.m. the unit entered Mode 6 (fuel in the reactor vessel, reactor vessel head removed or detensioned) to load the core for cycle 8. The inspectors observed the Mode 6 entry from defueled to determine if procedures were followed and Technical Specification Limiting Conditions for Operations (TS LCOs) were satisfied. Procedure GP-009, Refueling Cavity Fill, Refueling and Drain of the Refueling Cavity, Revision 13, was applicable to this evolution.

b. Observations and Findings

The inspectors observed that the prerequisites for Mode 6 entry from defueled were completed prior to the 6:30 a.m. shift turnover meeting on May 8, 1997. The prerequisites were contained in procedure GP-009. A problem with the IDP-1A-SIII instrument bus occurred at 6:44 a.m. that morning which caused the SIII inverter output breaker to trip. This caused equipment served by that bus to be inoperable as listed in AOP-24, Loss of Uninterruptible Power Supply, Revision 11. Included were the fuel handling building (FHB) emergency exhaust train "A" (E-12 fan) and the control room emergency filtration train "A" (R-2A fan) which were required for Mode 6. Immediately after the shift turnover, FHB emergency exhaust train "B" (E-13 fan) was placed in service to comply with TS 3.9.12 since the operable emergency power supply (emergency diesel generator B-SB) was on that train. The shift operations crew assumed that entry into the 7-day action statement for TS LCO 3.7.6 for having one train of control room ventilation inoperable would allow compliance with that specification. The shift operations crew assessed that Mode 6 could be entered in this condition and that TS 3.0.4, which prohibits TS Operational Mode entry while relying on TS LCO action statements, did not apply. The operations crew did not reassess the control room ventilation equipment failure against the GP-009 Minimum Equipment List in Attachment 6 for the defueled to Mode 6 change. Attachment 6 identified that both trains of control room ventilation were required for Mode 6 entry. Mode 6 was subsequently entered at 7:18 a.m. with one train of control room ventilation inoperable.

The inspector observed that at 8:15 a.m. the work control center informed the control room operators that Technical Specification 3.0.4 had been violated due to the plant reliance on a TS 3.7.6 action statement for Mode 6 entry. Condition Report 97-02485 was written to document this problem. The inspector noted that TS 3.9.12 (for FHB emergency exhaust) had an exemption to TS 3.0.4 while TS 3.7.6 did not. The licensee evaluated this failure to comply with TS 3.0.4 and determined that since it had been missed, it would not make sense to defuel, wait for restoration of the "A" train control room ventilation system to operable, and then re-enter Mode 6. The licensee continued with fuel reload as if TS 3.0.4 had been met, and continued to rely upon the TS 3.7.6 action statement for the inoperable ventilation train. The

work to repair the SIII instrument bus was not considered as a restraint to fuel movement.

The inspector reviewed the TS 3.0.4 Bases section and discussed the significance of TS 3.0.4 with licensee management. The TS 3.0.4 basis state that the intent is to ensure that facility operation is not initiated with either required equipment or systems inoperable or other specified limits being exceeded. The inspector pointed out that TS 3.0.4 established the safety level at which a mode change can be made by ensuring that the full complement of systems, equipment, and components are operable. The inspector also pointed out that TS 3.0.4 does not have an action statement, therefore it must be complied with. Even though a mistake had been made in making the mode change without complying with TS 3.0.4, once discovered, the intent must be complied with. After discussing TS 3.0.4 with the licensee, the inspector observed that the licensee immediately stopped fuel load until all equipment required for Mode 6 was operable.

Regulatory Significance

Technical Specification 3.0.4 requires that entry into an Operational Mode or other specified condition shall not be made unless the conditions for the Limiting Condition for Operation are met without reliance on provisions contained in the Action requirements. Exceptions to these requirements are stated in the individual specifications. In this case TS 3.7.6 was not met at the time that Mode 6 was entered from defueled and did not contain an exception to TS 3.0.4. This was also contrary to the prerequisites established in procedure GP-009. This failure was identified by the licensee, but not corrected until prompted by the inspectors. The failure to comply with TS 3.0.4 and procedure GP-009 is identified as a violation (50-400/97-04-01).

c. Conclusions

The inspector concluded that a violation of TS 3.0.4 had occurred. Although the violation was licensee-identified, the inspector concluded that the licensee's initial corrective action was inadequate.

02 Operational Status of Facilities and Equipment

02.1 Engineered Safety Feature System Walkdowns

a. Inspection Scope (71707)

The inspectors used Inspection Procedure 71707 to walk down accessible portions of the following ESF systems inside reactor containment during the refueling outage:

- Residual Heat Removal/Low Head Safety Injection System (FSAR Section 5.4.7)
- Auxiliary Feedwater System (FSAR Section 10.4.9)
- Containment Spray System (FSAR Section 6.5.2)

- Component Cooling Water System (FSAR Section 9.2.2)
- Chemical and Volume Control System (FSAR Section 9.3.4)

The inspectors used the current simplified flow diagrams and equipment lineup checklist from the operating procedures of each system to verify the correct valve and instrument lineup.

b. Observations and Findings

The inspectors found valve and breaker positions to be in accordance with the applicable mode of the unit. Material condition of the systems were adequate.

c. Conclusions

Equipment operability, material condition, and housekeeping were acceptable in all cases. The inspectors identified no substantive concerns as a result of these walkdowns.

04 Operator Knowledge and Performance

04.1 Boron Thermal Regeneration System (BTRS) Over-Dilution Event

a. Inspection Scope (71707)

The inspectors reviewed and evaluated the circumstances surrounding the first of two reactor coolant system (RCS) boron dilution events which occurred within two weeks of each other. The first event occurred on March 29, 1997, the last day of the previous inspection period, and was fully evaluated during this inspection period to assess root and contributing causes along with corrective actions.

b. Observations and Findings

On March 29, 1997, with the plant operating in Mode 1 at 100 percent power, a control board operator initiated a routine RCS boron dilution evolution for what was intended to be 2 minutes using the BTRS in dilute mode. This system uses a temperature dependent ion-exchange process via one of several demineralizer beds to raise or lower boron concentration. The BTRS system reduces radioactive waste and offers finer control of average RCS temperature near the end of the fuel cycle when control rods are full out and cannot be relied upon for that function. The operator intended to "bump up" RCS average temperature (to match reference temperature) just before shift turnover for the oncoming shift.

The operator obtained permission from the Unit Senior Control Operator (SCO) to perform the evolution and initiated the dilution at 5:16 a.m. without notifying anyone else on shift of his actions. The operator was somehow distracted and his attentions were diverted from this evolution. The RCS dilution via BTRS continued for thirty minutes until approximately 5:46 a.m. when the operator walked by the digital nuclear instrumentation drawers which indicated that reactor power was at 100.3

percent. The operator immediately realized the error, secured the dilution, and informed his management of the incident. Operations personnel generated Condition Report 97-01348 for this event.

Safety Significance

As a result of the error, RCS temperature increased approximately 0.2 degrees Fahrenheit, and indicated reactor power increased to 100.3 percent. A subsequent required flux map indicated that no core thermal limits were exceeded. RCS boron concentration was reduced less than approximately 6 parts per million as determined by comparing the March 29, 1997 RCS sample results to those of the previous day. While these numbers represented only a slight adjustment in core reactivity, the event itself uncovered some nonconservative approaches to reactivity management. First, BTRS dilution evolutions were not routinely entered in the control operator's logbook by all operators. These dilutions were considered to be so frequent and short in duration that logging was arbitrary. Secondly, the reactor operator did not feel the need to communicate this reactivity manipulation to the BOP operator or other crew members. The operator also did not use a 5-minute timer that was provided as an operator error reduction tool for this evolution. Finally, the Unit SCO did not adequately supervise the RO or monitor reactivity manipulations. The inspectors considered these actions to be precursors to potentially more significant reactivity control problems given different circumstances.

Regulatory Significance

10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. This requirement is further delineated in the licensee's Corporate Quality Assurance Program Manual, Section 12.0, Conditions Adverse to Quality (CATQ) and Corrective Action, Revision 18. The licensee's corrective actions for recent violations associated with operator errors included establishing a Near Term Improvement Plan with several initiatives for improving performance. These corrective actions were discussed in the licensee's response to NRC Violation 50-400/96-09-01 dated December 9, 1996. Among those initiatives were improving consistency between shifts, improving communications within operations, improving utilization of human error prevention techniques, and improving human performance in general. Licensee personnel failed to effectively implement the previous corrective actions as exemplified by the human errors which lead to the March 29 over-dilution event is considered a violation of 10 CFR 50, Appendix B, Criterion XVI (50-400/97-04-02, Example 1).

c. Conclusions

The March 29 over-dilution event represented failures in several areas including operations crew supervision, reactivity management, and communications between operators. This example marked a continuing

trend in human performance problems which have lead to a number of LERs and NRC violations in late 1996 and early 1997. One violation was identified for ineffective implementation of actions to correct this adverse trend.

04.2 Chemical and Volume Control System (CVCS) Boron Dilution Event

a. Inspection Scope (71707)

The inspectors reviewed and evaluated the circumstances surrounding the second of two boron dilution events which occurred within two weeks of each other. The second event involved errors in operations and engineering with respect to the design and operation of the primary makeup portion of the CVCS. The inspectors' reviewed the licensee's root cause investigation for this event to determine if root and contributing causes and corrective actions were adequately addressed. The engineering contributions to the primary makeup system problems were thoroughly researched by the licensee and are discussed in report Section E2.1.

b. Observations and Findings

On April 7, 1997, with the plant in Cold Shutdown (Mode 5), operators were preparing to fill the RCS pressurizer solid in accordance with plant procedures. Initial RCS boron concentration was 2340 parts per million (ppm). During previous plant outages, operators had received boric acid flow deviation alarms while attempting to maintain adequate boric acid flow to support the required RCS boron concentration of 2340 ppm during RCS fill evolutions. In preparation for the April 7 evolution, operators discussed the potential for the deviation alarms and recommended corrective actions based on previous experiences following indications of inadequate boric acid flow from flow control valve FCV-113A. A combination of erroneous assumptions and poor communications between shift supervision and control board operators lead to the events that followed.

Sequence of Events

Following an automatic makeup to the volume control tank (VCT) on April 7, a boric acid flow deviation alarm occurred which automatically secured primary makeup. This alarm was due to inadequate boric acid makeup flow to the blender (actual flow did not match the demand flow of 39 gpm as sensed by flow transmitter FT-113). Operators responded by starting the standby boric acid transfer pump (BATP) and restarting automatic makeup. This initial action cleared the flow deviation alarm but was not an action identified in annunicator panel response procedure (ALB-006-8-4). All subsequent makeups were to be performed in the manual mode, as instructed to operators by the shift superintendent.

The April 7 automatic makeup occurred due to low VCT level and was unrelated to the pressurizer filling evolution. All subsequent (manual) makeups were made to support filling the pressurizer to a solid (water-

filled) condition. The control board operator initiated a manual makeup to the VCT at 5:00 a.m on April 8 in accordance with OP-107, Chemical and Volume Control System, Revision 15, Section 8.7. Blended primary makeup/boric acid flow was directed to the top of the VCT (through the VCT spray nozzle) versus the normal flow path to the suction of the charging/safety injection pumps (CSIPs). The operator chose this flowpath because of a concern for possible thermal affects on reactor coolant pump seals (even though this concern was unfounded since automatic makeup normally flows to the suction of the CSIPs anyway). Flowing blended primary makeup/boric acid water to the top of the VCT through the spray nozzle limited boric acid flow to approximately half of the 39 gpm needed to support the shutdown boron concentration of over 2340 ppm. Both boric acid flow deviation and total makeup water flow deviation alarms came in but were assumed by the control board operator to be expected due to the manual mode of operation. The control board operator did not refer to the annunciator panel response procedures for these alarms and did not check boric acid or primary makeup water flow rates. The control board operator initiated three subsequent manual makeups with similar results (actual boric acid flow rates of 19-20 gpm versus the demanded 39 gpm and resultant flow deviation alarms). The flow deviation alarms were dismissed as "nuisance alarms". Two of the three subsequent evolutions were not entered in the control operator's logbook. Each of the four manual makeups during this shift lasted only minutes at a time and involved single BATP operation.

Following shift turnover at 6:54 a.m. on April 8, the oncoming shift, who had been briefed on the "nuisance alarms", initiated its first manual makeup to the VCT per OP-107 using the same potentiometer settings for boric acid flow and total makeup flow that were used by the previous shift. Upon receiving the flow deviation alarms again, the control operator referred to the annunciator panel response procedure and, in an attempt to increase boric acid flow, started the standby BATP. This only increased boric acid flow from 18 to 20 gpm as limited by the flow path alignment to the top of the VCT. The operator initiated a second manual makeup to the top of the VCT a few minutes later (the first had been secured due to the VCT reaching the upper end of its operating pressure band). Again boric acid flow was limited and deviation alarms came in. Operators suspected that the boric acid filter was clogged and directed an auxiliary operator to bypass it. With the boric acid filter bypassed, a third and final manual make-up was initiated at 7:40 a.m., again with two BATPs running and similar results.

Following the third (seventh total) manual makeup, the April 8 day shift Unit Senior Control Operator made a decision to return the primary makeup system to the automatic mode and that both BATPs would be used. The rationale was that the automatic alignment (to CSIP suction versus the top of VCT) would provide sufficient boric acid addition to keep up with the pressurizer fill rate at the higher boron concentrations. At this point, another control board operator raised the concern that the previous manual makeups might have reduced overall RCS boron concentration. At 8:20 a.m, the plant was declared solid and an RCS

boron sample was ordered. The resultant boron concentration was 2283 ppm, or 57 ppm less than the last sample indicated the day before. This boron dilution represented the cumulative result of the seven manual makeup operations performed between 5:00 a.m and 7:40 a.m on April 8. Licensee personnel generated Condition Report 97-01582 for this event.

Safety Significance

An important implication of this event was that operators inadvertently inserted positive reactivity into a shutdown reactor. The safety consequences from this event were minimized by the fact that the minimum required boron concentration to ensure shutdown margin was 801 ppm. The 2283 ppm boron concentration at the end of the dilution event was more than twice this amount. However, this incident, when coupled with the example discussed in report Section 04.1, represents a failure of the licensee's organization to effectively implement corrective actions or lessons learned from previous events. These include other industry events related to reactivity management and events at the Harris plant related to recent operator human performance trends.

Another consequence of the second shift's actions to start a second BATP with blended primary makeup/boric acid water discharging to the VCT spray nozzle was that the "A" BATP was deadheaded for several minutes. Previous NRC generic correspondence to licensees (IE Bulletin 88-04, Potential Safety-Related Pump Loss) cautioned against parallel pump operation with both pumps in a piping configuration that did not preclude pump-to-pump interaction during miniflow operation. While the bulletin and the licensee's resultant procedural cautions were focused on restrictions during miniflow operation, the intent of this guidance was to prevent the type of operation that occurred on April 8, 1997. The inspectors concluded that some operations personnel did not fully understand the intent of the guidance and that this guidance was not clearly stated in operating procedure OP-107, Revision 15, or in the CVCS System Description, SD-107, Revision 6.

The practice of not referring to annunciator panel response procedures following alarms was the most safety significant factor related to overall plant operation revealed from this event. This practice had been previously discussed in Inspection Report 50-400/97-300, in relation to operator license examination observations; Inspection Report 50-400/97-03, in relation to training staff performance; and for Violation 50-400/96-11-01, Example 2, in relation to heat trace temperature monitoring alarms.

Regulatory Significance

10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. This requirement is further delineated in the licensee's Corporate Quality Assurance Program Manual, Section 12.0, Conditions Adverse to Quality (CATQ) and

Corrective Action, Revision 18. As discussed in report section O4.1, the licensee has initiated extensive corrective actions to address previous violations associated with operator performance. Although this event was licensee identified, the licensee's implementation of actions in response to previous violations was not effective in preventing the dilution events discussed in this report. The failure to effectively implement corrective actions to prevent the April 8 dilution event is considered the second example of the violation cited in report section O4.1 against 10 CFR 50, Appendix B, Criterion XVI (50-400/97-04-02, Example 2).

Corrective actions completed during this inspection period included replacing the valve trim (plug and cage assembly) for FCV-113A to allow greater boric acid flow. Post-modification testing had not been completed at the end of the inspection period. Additionally, procedure OP-107 was revised to preclude aligning blended boric acid/primary makeup water flow to the VCT spray nozzle and to provide better guidance for responding to the boric acid and total flow deviation alarms.

c. Conclusions

The boron dilution event discussed in this section was the result of human performance errors during the operation of the primary makeup portion of the CVCS system. The inspectors concluded that, prior to the event, some operators did not thoroughly understand certain limitations of the system. This lack of understanding lead to errors in judgement and decision making. The practice of not referring to annunciator panel response procedures following alarms was also a significant factor. In addition, poor communications between shift supervision and control board operators contributed significantly to the event. One violation was identified for failing to effectively implement actions to correct human performance problems associated with previous violations in plant operations.

O7 Quality Assurance in Operations

O7.1 Licensee Self-Assessment Activities (40500)

During the inspection period, the inspectors reviewed multiple licensee self-assessment activities, including the root causes for the violation examples discussed in Operations and Maintenance. The inspectors considered the licensee's root cause efforts to be thorough for the boron dilution events and the TS 3.0.3. entry for CCW. As discussed in report section M3.1, the root cause investigation for the containment hatch missile shield removal did not consider prior opportunity to identify or address this issue.

08 Miscellaneous Operations Issues (92700, 90712, 92901)

08.1 (Closed) LER 50-400/97-007-00: Inoperable Component Cooling Water System -Technical Specification 3.0.3 Entry

This event was reported because the licensee connected the non-seismically qualified chemical addition piping section to both trains of the Component Cooling Water (CCW) System at the same time. LER 96-013-01 had reported the licensee's discovery that the chemical addition section piping was not seismically qualified. In LER 96-013-01 the licensee stated in the corrective actions completed section that the CCW System Operating Procedure (OP-145) was revised on November 14, 1996 to ensure that the CCW trains are separated prior to and during chemical addition and that the affected CCW train during this evolution would be declared inoperable. LER 97-007-00 states that the November 1996 procedure revision did not separate the trains. This was discovered on January 4, 1997 when operations personnel were reviewing the procedure prior to use. The procedure was revised and was used successfully after that.

On March 25, 1997, this procedure was used to add chemicals to the CCW system and both trains were connected to the chemical addition piping section. A note had been left in the procedure that stated to ensure the chemicals are flushed to the in-service header. This note did not make sense because the procedure required the headers to be split prior to the chemical addition evolution which placed both headers in service. This confused the operators and after stopping the evolution and discussing this note they decided that the A-train was the previously in-service header and would be the train that the chemicals would be discharged into. The operators forgot that the B-train had been lined up to the chemical addition piping to supply flushing water. Nine minutes after the alignment was established the operators realized that they had made an error, stopped the evolution, and realigned the valves.

The LER listed the cause as a combination of not following procedure convention regarding the use of parenthetical component names/numbers for dual train systems, inadequate familiarity with the intent of a procedure change, and a misleading note in the procedure that contributed to confusion in this scenario. However, the inspector concluded that the note concerning alignment to the inservice header was what caused the confusion and that this should have been removed by November 14, 1996 as stated in LER 96-013-01. The confusion in following convention was caused by trying to comply with the note.

Regulatory Significance

10 CFR 50 Appendix B Criterion XVI requires that conditions adverse to quality be identified and corrected. For significant conditions adverse to quality, measures shall be taken to determine the cause and corrective action taken to preclude repetition. The licensee established corrective actions for a significant condition adverse to quality in LER 96-013-01. Those corrective actions were not adequately

implemented in that the procedure change identified was not adequate to correct the problem, resulting in its recurrence on March 25, 1997. This is considered a violation of 10 CFR 50 Appendix B Criterion XVI for ineffective corrective action (50-400/97-04-02, Example 3).

Corrective action for this LER will be tracked and reviewed as part of the violation. This LER is closed.

08.2 (Closed) LER 50-400/97-005-00: Failure to Perform Core Flux Mapping Following Plant Operation with Reactor Power Greater than 100 percent.

This event was reported due to a failure to perform core flux mapping when power was found above 100 percent. This event is addressed by violations 50-400/97-01-03 and 50-400/97-03-01. Corrective actions will be reviewed during closure of the violations. This LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (62707)

The inspectors observed all or portions of the following work activities:

- 96-AHBH1 Perform CM-M0009, Jamesbury Butterfly Wafer-Sphere Valves - 14-20" Disassembly and Maintenance, Revision 5, on Valve 1SW-83.
- 96-ACMB1 Perform CM-M0226, Anchor/Darling Butterfly Valves, Revision 0, on Valves 1SW-274 and 1SW-40.
- AMPA-001 Perform MPT-M0091, Heat Exchanger Opening/Closing for NRC Generic Letter 89-13 Inspection, Revision 4, on the Component Cooling Water "B" Heat Exchanger.
- AGWG-002 Perform CM-I0002, AC Limitorque Setup Check and Stroking, Revision 9, on Valve 1SI-327.
- ALCC-001 Perform PM-I0043, Motor Operated Valve Testing and Calibration, Revision 5, on Valve 1RH-63.
- MST-E0001 6.9 kv Reactor Coolant Pump Circuit Breaker Inspection and Testing, Revision 6.
- LP-T-0408 TAVG\Delta T Control Including: Rod Control, Power Mismatch, Low Power Feedwater Control, Steam Dump Control, TREF-TAVG, Rod Control (speed and direction), and Reduced TAVG Load Follow, Revision 6.
- FHP-044T Siemens S-0253-31/NF991004 Temporary Procedure for Instrument Thimble Extraction from Fuel Assembly HJ57, Revision 0.
- PM-I0009 Incore Instrument Thimble Insertion, Retraction, Removal, and Replacement, Revision 5.
- AEQP-001 Perform MST-M006, Emergency Diesel Generator Fuel Oil Storage Tank Inspection, Revision 7.

The inspectors found the work performed under these activities to be professional and thorough. All work observed was performed with the work package present and in active use. Technicians were experienced and knowledgeable of their assigned tasks, procedures were present and followed, work areas were controlled, and instrumentation was calibrated. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure. When applicable, appropriate radiation control measures were in place.

M1.2 Transfer of Heavy load Into Containment

a. Inspection Scope (62707)

The inspectors reviewed and observed portions of the movement of a replacement Reactor Coolant Pump (RCP) motor into the containment. Structural engineering evaluations and contingency plans were also reviewed.

b. Observations and Findings

The licensee changed out one of the RCP motors with a refurbished motor as part of their preventative maintenance program. The licensee plans to replace the other two RCP motors during the next two refueling outages at a frequency of one per outage. The licensee will then replace each RCP motor on a ten year cycle at the refueling outage. This outage, RCP "B" motor was replaced. The inspector observed the replacement motor lifted by the vendor's crane over the refueling water storage tank (RWST) and lowered into the containment hatch bay. Transport of the motor was well controlled. From the bay, the motor was moved into containment on a specially constructed rail car, and was seismically restrained to the equipment hatch platform.

The inspectors reviewed the preparations for transporting the RCP motor. Since the path exposed the RWST to potential damage if the load dropped, plant systems were realigned to provide alternate boration sources. The load was over the tank for a minimal time (20 seconds). The alternate path, over the waste process building, required walking the crane with the load lifted high and involved lowering the crane boom to a potentially dangerous angle to reach the equipment hatch bay. The Plant Nuclear Safety Committee reviewed and approved the transport path. The inspectors determined that prior to the load lift, the crane was inspected and load tested to 125 percent of capacity. Also, crane operators were experienced and certified.

c. Conclusions

The inspectors concluded that transport of the reactor coolant pump motor into containment was well executed.

M1.3 Observation of RFO-7 Emergency Diesel Generator 10-Year Inspection / Overhaul

a. Inspection Scope (62707)

The inspectors reviewed the work scope for the RFO-7 Emergency Diesel Generator (EDG) 10-Year inspection/overhaul, observed inspections and overhaul work in progress on the "A" and "B" EDGs, and reviewed completed work packages for the "B" EDG. Training records were also reviewed for selected EDG outage maintenance personnel.

b. Observations and Findings

Review of RFO-7 EDG Work Scope

RFO-7 was the first 10 year inspection/overhaul scheduled for the two EDGs. The inspectors reviewed: Harris Operating License, Technical Specifications, NUREG 1216 [SER on Operability and Reliability of Transamerica Delaval, Inc. (TDI) EDGs], TDI EDG Owners Group Generic Topical Report TDI-EDG-001A, TDI EDG Vendor Manual MBO, Procedure PLP-113, Emergency Diesel Generator Reliability Program, Revision 2, Cooper Enterprise Service Information Memorandum (SIM) 402A (Nuclear Maintenance Management System - Preventive Maintenance Program), and the RFO-7 EDG work activities. PLP-113 included the requirements specified in the TDI EDG vendor manual MBO and Cooper Enterprise SIM 402A.

Observation of EDG Inspection/Overhaul Work Activities

The inspectors witnessed work activities and inspections in progress during the overhaul of "A" and "B" EDGs. Activities were well coordinated and controlled and work was done in accordance with work packages which were present at the work location. The work was performed by a crew consisting of licensee shared resource personnel and vendor maintenance/engineering personnel under direction of Harris maintenance personnel. The personnel were knowledgeable of their assigned tasks.

Engine/Component inspections performed were thorough and marginal components and parts were identified for disposition. System engineer and vendor engineers were involved in resolving the issues. Examples of marginal parts discovered and replaced included the "B" EDG camshafts, and a fuel tappet and jacket water drive gear on the "A" EDG.

EDG Cylinder Liner Inspection

During RFO-7, 6 cylinder liners were replaced as scheduled in the "A" EDG and 10 in the "B" EDG. These cylinder liners were removed and inspected using procedure CM-M0151, Emergency Diesel Generator Piston, Rod and Liner Removal and Inspection, Revision 6. The inspectors witnessed wet bath fluorescent magnetic particle non-destructive examination (NDE) inspection of the cylinder liner flange radius area on several cylinder liners removed from the "A" EDG. There was a 10 CFR 21

report on loose fit liner cracking in this area and the inspections were recommended by the vendor. The vendor recommendation was that for engines with less than 3000 operating hours, 25 percent of the cylinder liners should be inspected for circumferential cracking at the top liner flange radius at the next refueling outage. All liners should be inspected/replaced prior to 3000 operating hours. The "A" EDG and the "B" EDG had approximately 1300 and 1000 operating hours respectively. If any liner was detected to have a continuous circumferential (360 degree) indication then that liner would be removed from service and additional liners would be inspected. Cylinder liners removed from the Harris EDGs were replaced with new liners, no liners were reused. Upon initial NDE inspection, 2 liners showed 360 degree indications, 2 showed partial indications, and two showed no indications. These were documented on NDE data sheets. Subsequently the liner radius areas were further cleaned and re-examined. This additional examination was not documented on the NDE data sheets. The licensee sectioned several of the liners and sent them to the CP&L metallurgical laboratory for analysis. Licensee system engineering and the vendor were involved in evaluating the liner issue.

The CP&L metallurgical laboratory indicated that the liner surface conditions observed were machining marks and grain boundaries and not true indications. The inspectors observed the samples at the metallurgical laboratory and discussed the issue with laboratory personnel. Cooper Energy Services Engineering personnel provided an engineering evaluation which indicated that all the liners should be inspected by the 3000 hour operating limit. The inspectors reviewed the licensee EDG overhaul plan and verified that the liner replacement would be complete by RFO-10 well before the 3000 hour operating limit. The evaluation of the EDG cylinder liner issue was thorough.

Review of Completed Work Packages

The inspectors reviewed the following completed work packages for work performed on the "B" EDG: 96-AEDX1, AGXM002, 97-AEBG1, 97-ADRK1, 96-AFZL1, 95-ALLJ1, AEOT001, and 96-AFZM1. Training records for selected CP&L shared resource personnel and vendor personnel were reviewed. The inspectors noted that the instrumentation used was in calibration and that personnel signing procedure steps had been trained for the work activities.

Work packages were generally complete however a discrepancy was noted regarding the NDE data sheet for the cylinder liner flange filet radius inspections performed on the liners removed from the "B" EDG. The description of work performed in work package 96-AEDX1 indicated that the inspections were performed on 10 liners removed from the "B" EDG and that no reportable indications were observed. The NDE report was not contained in the work package and could not be located. The NDE inspector was interviewed and the inspectors verified from the discussion and his notes that he had performed the inspection and that no reportable indications were found. This information agreed with the

description of work included in the work package. The licensee completed a new data sheet to include in the package.

c. Conclusions

The work scope for the RFO-7 EDG inspection overhaul met the requirements of plant procedures, the vendor manual, and the vendor service information memorandum regarding 10-year surveillance and maintenance activities. The EDG work activities observed were conducted per procedure in a professional manner by knowledgeable personnel. The engine/component inspections performed were thorough and identified problems were conservatively resolved. Some discrepancies were noted regarding documentation of NDE inspections on EDG cylinder liners.

M1.4 "A" Steam Generator Foreign Objects

a. Inspection Scope (71707)

The inspectors used Inspection Procedure 71707 to observe the licensee's activities involving the removal of foreign objects from the "A" steam generator. The inspectors observed the videotapes of the licensee's inspection of the "A" steam generator, the foreign objects removed from the "A" steam generator, and the feedwater check valve, 1FW-158, where two bushings found in the "A" steam generator originated from.

b. Observations and Findings

A foreign object was detected in the feedwater preheater section of the "A" Steam Generator, during the inservice inspection of the tubes. A section of the feedwater line was removed and a camera was used to search for foreign objects. The licensee found two hinge pin bushing sets from feedwater check valve 1FW-158, a piece of duct tape, and a piece of the center rib from the preheater section of the "A" steam generator. These objects were removed from the "A" steam generator, and the licensee evaluated and plugged the tubes damaged by the foreign objects.

The two hinge pin bushing sets (each consisting of two eccentric bushings held together by a tack weld) were located on individual shafts inside valve 1FW-158 and each held in place by a single tack weld to the check valve disk. Each weld was in the feedwater flow path, and had deteriorated due to erosion. Once the welds broke, the bushings came off their respective shafts and entered the "A" steam generator through the main feedwater nozzle. All three of the feedwater check valves (1FW-158, 1FW-216, and 1FW-276) were inspected and refurbished using new bushings. The bushings were attached to the disk using several welds of increased size in lieu of the original single tack weld method.

Parts of the "A" steam generator preheater ribs around the inconel target plate were found to be eroded. The licensee documented the erosion of the center ribs (upper and lower) and the two side ribs of the "A" steam generator preheater region in Condition Report (CR)

97-02600. The steam generators' vendor was evaluating their condition for operability at the end of the inspection period.

c. Conclusions

The inspectors concluded that licensee activities involving the detection and recovery of foreign objects in the "A" Steam Generator were conducted in an acceptable manner. The licensee performed an adequate analysis of the cause of the foreign objects, and a review of the potential for foreign objects entering the other steam generators. The licensee was evaluating the operability of the "A" steam generator for the degraded preheater condition at the end of the inspection period.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Surveillance Observation

a. Inspection Scope (61726)

The inspectors observed all or portions of the following surveillance tests:

- OST-1033, Daily Surveillance Requirements Daily Interval, Revision 12.
- OST-1091, Containment Closure Test Weekly Interval During Core Alterations and Movement of Irradiated Fuel Inside Containment, Revision 4.
- OST-1801, ECCS Throttle Valve, CSIP and Check Valve Verification, Revisions 10, 10/1, and 10/4.
- OST-1824, 1B-SB Emergency Diesel Generator Operability Test, Revision 11/1.
- EST-209, Type B Local Leak Rate Tests, Revision 9.
- MST-M0006, Emergency Diesel Generator Fuel Oil Tank Inspection, Revision 7.

b. Observations and Findings

The inspector found that the testing was adequately performed. During the loss of offsite power and safety injection actuation testing (procedure OST-1824), plant equipment responded as expected. Some of the outage-related surveillance procedures required temporary changes either immediately prior to or during their performances. The changes were either technical or administrative in nature, but indicated that some of the test conditions or requirements had not been fully thought out during the procedure development and review stages. Specific problems with certain surveillance tests are discussed in sections M2.2 and M2.3 below.

c. Conclusions

The surveillance performances were adequately conducted. However, many of the surveillance test procedures required temporary changes immediately prior to or during their performance indicating that many of the test conditions or requirements had not been thoroughly examined during the procedure development and review stages. The deficiencies were identified by licensee personnel and documented in condition reports.

M2.2 Problems with Remote Shutdown System Test Procedure

a. Inspection Scope (62700)

The inspectors reviewed and observed portions of Operations Surveillance Test OST-1813, Remote Shutdown System Operability, Revision 7/4.

b. Observations and Findings

OST-1813, an 18-month (outage) surveillance test, was performed to verify the ability to control plant cooldown from outside the main control room. Operability of transfer switches, monitoring instrumentation and annunciators were verified as required by Technical Specification 4.3.3.5.2. The inspectors observed the pre-briefing, portions of Section 7.2 Test B: NNS Transfer Panel 1A-SA and Auxiliary Transfer Panel 1A-SA, and portions of Section 7.3 Test C: Transfer Panel 1B-SB and Auxiliary Transfer Panel 1B-SB. Observations were made from the transfer panels, the auxiliary transfer panels, and the auxiliary control panel. The inspectors noted that an approved, continuous use procedure was present and followed by the test personnel. Communications were established between the control room, auxiliary control panel, the auxiliary transfer panels, and the transfer panels. The steps were performed in sequence at the command of the test director, and the results recorded and evaluated.

The inspectors noted that some events such as equipment starts and annunciator alarms were not anticipated as the transfers were made. The inspectors considered that the procedure caused a number of unnecessary delays. In one case, upon the initiation of transfer of the SSPS, annunciator alarms (Low Pressurizer Pressure SI and Low Steam Line Pressure SI) were unexpectedly received. The licensee stopped the test and investigated the cause of the alarms. The alarms were determined to be valid but were not identified as expected by the procedure.

Subsequent to the test the licensee issued a condition report (CR) 97-01890 on anomalies of the test. Fifteen recommendations were made to improve the test consisting mostly of procedure changes to identify expected equipment responses and improve test sequences.

c. Conclusions

As a result of the procedure problems, the test performance was considered weak. This test has been performed at each of the previous six outages and procedure problems still existed.

M2.3 Problems with High Head Safety Injection System Test

a. Inspection Scope (61726)

The inspector observed portions of OST-1801, ECCS Throttle Valve, CSIP, and Check Valve Verification, 18-Month Interval, Mode 6, Revision 10.

b. Observations and Findings

The inspectors observed operators perform Section 7.3 of OST-1801, which established a differential pressure for the "B" charging/safety injection pump (CSIP) to setup for collecting pump performance data. During the test, after operators started the pump and throttled the discharge isolation valve to obtain the desired differential pressure, the pressure exceeded the allowable band by 47 psid. The pump was secured and the procedure reviewed to determine if there was a problem with the system alignment. Plant personnel discovered that the "B" CSIP was aligned to the alternate cold leg injection path for this test which was a different alignment than had been specified in previous procedure revisions.

The procedure was revised to incorporate the normal flow path through the boron injection tank (BIT) and when the test was subsequently run, the pump performance data was still outside the acceptance criteria. The pump was again secured and troubleshooting began. Plant personnel determined that the seal injection flow path from the CSIPs was not in service, another anomaly that was different from the previous revisions of the procedure. The procedure was again changed and the test rerun with similarly unacceptable results. The procedure went through four temporary changes before the test data (which was still outside the acceptance criteria range established in the procedure) was presented to engineering for further evaluation.

Licensee personnel later determined that the pump's data matched the test performance curve with negligible degradation indicated, that the pump's operability was unaffected, and that the procedural acceptance criteria was erroneous (for either of the flow paths). Licensee personnel later informed the inspector that the flow and differential pressure criteria specified in the test procedure was the same criteria established in the procedure during the previous refueling outage and that test results then exceeded the allowable range as well.

c. Conclusions

The inspector concluded that although the licensee's actions to evaluate the data against the pump performance curve for operability before

making any changes to the system flow characteristics were commendable, the licensee's surveillance procedure review process was deficient to not have identified the erroneous criteria during or following the previous outage's performance of OST-1801.

M2.4 Safety Battery Fire During Five-Year Discharge Test

a. Inspection Scope (61726)

The inspectors reviewed circumstances surrounding a small fire on the 1A-SA emergency battery during a discharge performance test on April 28, 1997. The inspectors assessed licensee performance errors that led to the event and observed subsequent reperformance of the test to verify that the proper corrective actions had been implemented.

b. Observations and Findings

On April 28, 1997, maintenance technicians were performing procedure MST-E0013, 1E Battery Performance Test, Revision 6 for the 1A-SA emergency battery. This procedure implemented Technical Specification Surveillance Requirement 4.8.2.1.e. by verifying every five years that the emergency batteries' capacities were at least 80 percent of the manufacturer's rating when subjected to a performance discharge test. About one hour into the test, the technicians, who were sitting outside the battery room monitoring test parameters on a computer, smelled smoke coming from the room. Upon entry, they discovered small flames coming from a jumper cable attached to the number 1 battery cell. A technician extinguished the fire with a carbon dioxide extinguisher while another notified the main control room who then sounded an alarm and dispatched the plant fire brigade to the scene.

The inspectors arrived at the battery room within minutes of the fire and noted that minimal damage had occurred. The top plastic cover of the number 1 cell was burned through in an approximated two square inch area due to hot melted plastic insulation from the jumper cable that had been attached to it. The number 1 cell was the only one (of 60 total) that was damaged. The discharge test had been terminated and technicians had secured the test equipment. The damaged cell was later replaced and the discharge test was rerun the next day after the battery was recharged.

The inspectors learned through discussions with the technicians that the wrong jumper cable had been used to connect the load unit to the battery. Instead of using the parallel conductor 1/0 cables (with a mechanical bolted connection) which had been specifically designed for this test, the technician connected a single conductor 1/0 cable which used a standard alligator-style clamp-on connection. The combined effect of using a single conductor cable with a questionable connection to carry 298 amps resulted in the jumper cable plastic insulation heating up excessively, which caused the fire. The single conductor was usually used for another (lesser ampacity) 18-month surveillance test. The five-year test had been prebriefed the day before, and the

technician performing the test knew which cable to use, but made a cognitive error while connecting the load unit to the battery. The procedure did not specify which of the two jumper cable types to use.

Prior to reperforming the test, MST-E0013 was revised to include cautions to use the parallel conductor cables. The inspector observed the retest and verified that battery test acceptance criteria were satisfied. The inspector considered licensee personnel actions to revise this procedure to specify the parallel conductor cables to be appropriate.

Technical Specification 6.8.1.a. and Regulatory Guide 1.33, Appendix A, Section 8.b.(1)(q), require written procedures to be established, implemented, and maintained covering emergency power tests. The failure to adequately establish and implement procedural guidance for using the correct test equipment for the 1A-SA Emergency Battery was contrary to this requirement and is considered a violation. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-400/97-04-03).

c. Conclusions

A small fire resulted from using improper cables to test the 1A-SA emergency battery. The safety consequences from the fire were minimal in terms of plant equipment damage and personnel safety. One Non-Cited Violation was identified.

M2.5 Observation of Inservice Inspection (ISI) Work Activities For the Reactor Vessel

a. Inspection Scope (73753)

The inspector reviewed examination procedures, vessel scan plans, programmed calibration setup data, examiner certifications, and observed examination/evaluation activities for the first 10-year interval ultrasonic examinations of the Shearon Harris Reactor Vessel. See NRC Inspection Report No. 50-400/97-03 for a programmatic review of the first 10-year inservice inspection interval program.

b. Observations and Findings

Shearon Harris started commercial operation on May 2, 1987; therefore, the April 1997 refueling outage is the final outage of the first 10-year ISI Inspection Interval. One major inspection required for completion of the first ISI interval is the volumetric examination of the Reactor Pressure Vessel (RPV) and the attachment piping welds. The vessel examinations were conducted by Southwest Research Institute (SwRI) and selected examinations were witnessed by the inspector during the refueling outage (RFO-7). The 1983 Edition with Summer 1983 Addenda (83S83) is the ASME B&PV Code, Section XI "Code-of-Record" for the first 10-year inspection interval.

The inspector reviewed the ISI outage examination plan, the vessel scan plan, programmed calibration setup parameters, examiner certification records and the following ultrasonic examination/operation procedures to determine whether the procedural content, technical instructions and verification documentation were adequate:

- SHH-AUT14, Automated Ultrasonic Inside Surface Examination of Pressure Piping Welds, Revision 1
- SHH-AUT15, Automated Inside Surface Examination of Ferritic Vessels Greater than 4.0 Inches in Thickness, Revision 1
- SwRI-AUT2, Automated Inside Surface Examination Indication Resolution, Revision 10
- SwRI-AUT5, Southwest Research Institute PaR Device and Attachments Operation, Revision 4
- SwRI-AUT7, Southwest Research Institute PaR Device Assembly, Revision 4
- SwRI-AUT8, Southwest Research Institute PaR Device Calibration, Revision 3
- SwRI-AUT34, Southwest Research Institute PaR Device Checkout, Revision 3
- SwRI-AUT36, Checkout and operation of the 8-channel Enhanced Data Acquisition System, Revision 0
- SwRI-AUT38, Automated Ultrasonic System Performance Verification, Revision 1
- SwRI-EDAS2, Enhanced Data Acquisition System-II Performance Verification Procedure (Test Plan), Revision 3
- SwRI-PDI-AUT1, Automatic Inside Surface Ultrasonic Examination of Ferritic Vessel Wall Greater than 4.0 Inches in Thickness, Revision 2
- SwRI-PDI-AUT2, Automated Inside Surface Ultrasonic Flaw Evaluation and Sizing, Revision 2

In addition to the above reviews, the inspector analyzed examination data for the following welds concurrently with the SwRI Level III analyst to determine if the examiner was knowledgeable of the procedure requirements and whether examination results were recorded as specified in the ISI program and in the nondestructive examination (NDE) procedures:

- Outlet Nozzle to Shell @ 25°, Weld No. RV-NOZ-AO-N-06
- Outlet Nozzle to Shell @ 265°, Weld No. RV-NOZ-BO-N-02

- Meridional Weld @ 165°, Weld No. MHW-RV-14
- Meridional Weld @ 285°, Weld No. MHW-RV-12
- Meridional Weld @ 345°, Weld No. MHW-RV-11
- Intermediate Shell to Lower Shell Weld No. CSW-RV-03
- Outlet Nozzle to Shell @ 145°, Weld No. RV-NOZ-CO-N-04
- Meridional Weld @ 45°, Weld No. MHW-RV-16

c. Conclusions

Ultrasonic examinations witnessed by the inspector, and interpretation /evaluation/acceptance of the test results were conducted in a proficient manner by experienced and knowledgeable examiners.

M2.6 Steam Generator (SG) Eddy Current Examination and Data Evaluation Activities

a. Inspection Scope (73753 and 50002)

The inspector reviewed the licensee's steam generator eddy current program and examination procedures, examiner certification records, and observed site resolution analysts evaluating eddy current data. The site resolution group analysts resolved differences encountered in interpretation of data from the first eddy current data review group made up with a combination of Duke and ASEA, Brown, Boveri (ABB) analysts and located at the McGuire Nuclear Plant and the 2nd eddy current data review group performed by Framatone Technologies in Lynchburg, Virginia.

b. Observations and Findings

During RFO-7, the licensee had planned to perform a total of 18,948 eddy current examinations in the three Shearon Harris Steam Generators. The examinations were conducted using a combination of bobbin and Plus Point coil probes. The examinations performed with the Plus Point probe was a new addition to the technology used by the licensee to properly identify discontinuities in areas such as the top of tubesheet on the hot leg, rows 1 thru 3 U-bends, special interest areas, and the preheater expansion zone for steam generator A only. As a result of using the plus point probe, the licensee also expected to plug a higher number of tubes this outage.

The inspector examined the licensee's steam generator eddy current activities by reviewing the procedures listed below:

- Carolina Power and Light Company (CP&L) Steam Generator Strategic Plan, "Harris Nuclear Plant Strategic Plan," Revision 0

- CP&L Procedure PLP-651, Steam Generator Program, Revision 0

- CP&L Procedure EST-216, Steam Generator Tube Indication Tracking and Reporting Procedure, Revision 5

- CP&L Procedure HNP-100-005, Steam Generator Eddy Current Interpretation Guidelines, Revision 1

In addition, the inspector reviewed all examiner certification records and observed two resolution group analysts perform their analyses of the eddy current data. During the eddy current examinations on "A" Steam Generator, foreign objects were discovered in the preheat area below the feedwater inlet adjacent to the Row 49, Column 59 tube. These items were subsequently removed (report section M1.4). At the conclusion of the inspection, the licensee was also predicting that approximately 28 tubes would have to be plugged this inspection. This was a much higher number than normally plugged during previous outages. However, it reflected the improvements in inspection technology used this outage for the detection and evaluation of eddy current indications. Discussions with licensee cognizant engineers and vendor analyst personnel indicated that these individuals were well-trained, knowledgeable, and dedicated.

c. Conclusions

Steam generator eddy current activities were well-managed. Program and examination procedures were very good, knowledgeable/skillful vendor personnel were utilized, and state-of-the-art examination equipment was used.

M2.7 Ultrasonic Examination of Containment Liner

a. Inspection Scope (57080)

The inspector observed ultrasonic thickness examinations of the containment liner below the top surface of the concrete floor slab at the 0° and 85° azimuth. This inspection was performed to investigate corrosion noted on the liner during walkdown visual inspections documented in Condition Report 97-01880. The engineering evaluation of this issue is addressed in section E1.4 of this inspection report.

b. Observations and Findings

The following account of the inspection observed by the inspector was written in part, by the Level III ultrasonic examiner who developed the techniques used to acquire the containment liner measurements.

"As part of resolution of potential containment liner corrosion, it was deemed necessary to perform ultrasonic thickness testing (UT-T) of the liner below the 221-foot floor elevation. Because of the narrow gap where the Ethafoam had been removed between the containment liner and the concrete floor slab (1 inch - 5/8 inch range), conventional direct contact ultrasonic thickness testing with an inspector's hand on the UT transducer could not be done. Thus, it was necessary to devise an extension piece which could be used to position the transducer down in the gap and in suitable contact with the liner surface to obtain the thickness measurements.

The transducer extension was devised by mounting a select UT transducer on the end of an approximately 5½-foot length of ¼ inch x 1 inch flat metal bar stock. The actual transducer mounting location on the bar was machined to form a depression with a gradual taper so as to somewhat recess the transducer body and it's coaxial cable connection in the bar thereby reducing the overall thickness dimension of the extension piece. UT couplant was delivered to the transducer face area by small plastic tubing connected to a plastic hand syringe. Index marks were made on the bar at six inch intervals measured from the transducer centerline to facilitate positioning the transducer to obtain thickness measurements at six inch intervals down the liner from the floor level.

To obtain thickness measurements, the extension was lowered down into the gap to the first measurement position at the bottom, the couplant syringe pumped couplant to the transducer face area and the bar positioned so that the transducer face was in contact with the liner plate surface. For each of the subsequent thickness measurements, the bar was raised to the next 6 inch index mark on the bar was at floor level and the operation repeated.

Thickness measurements of the liner below 221-foot floor elevation using the extension process were taken at two containment azimuth locations: 355° azimuth (general referred to as the zero degree azimuth) and 85° azimuth (general referred to as the 90° azimuth).

The nominal thickness of the containment liner was .375 inch. The minimum UT thickness reading obtained at the 0° azimuth was .401 inch. The minimum UT thickness reading obtained at the 85° azimuth was .403 inch.

c. Conclusions

The inspector considered the licensee disposition of the containment liner thickness issue documented in Condition Report 97-01880, to have been resolved in a sound technical manner. Licensee ultrasonic examination personnel who performed the containment liner thickness measurements were resourceful, skillful and very knowledgeable.

M3 Maintenance Procedures and Documentation

M3.1 Containment Equipment Hatch Missile Shield Removal

a. Scope (37551)

The inspector reviewed the licensee's investigation and actions related to a problem found while removing the containment equipment hatch missile shields. Condition Report 97-01499 was written to address this issue. The inspector reviewed procedure CM-M0100, Containment Equipment Hatch Removal and Replacement, Revision 6 to determine whether the procedure allowed removal of the missile shields in Mode 3. The inspector reviewed the 10 CFR 50.59 safety evaluation screen, performed as Attachment 1 to procedure AP-011, 10 CFR 50.59 Safety Evaluations.

The inspector reviewed Technical Specification 3.6.1.1 and its associated basis, and FSAR section 3.3, 3.5, and 3.8.

b. Observations and Findings

The inspector found that the licensee Nuclear Assessment Section had identified on April 5, 1997 at approximately 1:00 p.m. that the containment equipment hatch missile shields were being removed and questioned whether containment integrity as required by Technical Specification 3.6.1.1 was being maintained. The licensee's investigation concluded that the plant had entered the Limiting Condition for Operation of Technical Specification 3.6.1.1 at 3:20 a.m. on April 5, 1997. The action statement required that the unit be in Hot Standby in 6 hours, however, the unit was already in that condition, and Cold Shutdown in the following 30 hours. The licensee initiated Condition Report 97-01499. Reinstallation of the missile shields was completed at 4:50 a.m. on April 6, 1997, within the time required by the action statement.

The inspector found that procedure CM-M0100 was revised on April 2, 1997 (Revision 6). The revision included a note under section 7.1, Missile Shield Removal, that allowed the missile shields to be removed anytime in Mode 3 through 6. The 10 CFR 50.59 safety evaluation screen was completed on April 1, 1997 and concluded that the activity does not require a change to the Technical Specifications. The licensee concluded that the 50.59 screening review was inadequate because it did not identify that the change to allow removal of the missile shields in Mode 3 required a Technical Specification change. Technical Specification 3.6.1.1 requires containment integrity be maintained in Modes 1 through 4.

The inspector observed that FSAR section 3.3, Wind and Tornado Loadings, described the containment structure as one that was designed to withstand design wind and tornado generated missiles. FSAR section 3.5, Missile Protection, states that protection of safety related systems and equipment, including the containment liner, from missiles is accomplished by various methods including barriers. Table 3.5.2.1, Barriers Designed For Missiles, lists the containment building as the structure that is designed to prevent external missiles from damaging the liner. Figure 3.5.1-01, Safety Related Structures Systems and Component Protected Against Tornado Missiles, shows the removable missile shield as protection for the equipment hatch. The inspector found that the missile shields were not specifically called out in the written portion of the FSAR. However, based on the written words for the containment building being a barrier for the liner and the missile shields being shown on Figure 3.5.1-01 around the equipment hatch, the missile shields performed the same function for the equipment hatch that the containment building performed for the liner. Licensee review of this information during the post event discussion on April 6, 1997 had come to the same conclusion.

The inspectors considered that reviews of the outage schedule, outage risk assessment, and operations review and work authorization could have caught this problem prior to initiation of missile shield removal. The inspector discussed this aspect with licensee management who initiated condition report 97-02333, since the original investigation had focused only on the inadequate procedure change and safety review.

Regulatory Significance

10 CFR 50.59, Changes, Tests, and Experiments, allows licensees to make changes in the facility and procedures as described in the safety analysis report without NRC approval unless it involves a change to the technical specifications or an unreviewed safety question. The procedure change authorized an evolution in a mode that was prohibited by the plant's technical specifications and therefore required that a technical specification change be submitted under 10 CFR 50.90. This is considered an apparent violation of 10 CFR 50.59 for making a change to the facility through a procedure that required a technical specification change without first seeking NRC approval (50-400/97-04-04).

c. Conclusions

The inspector concluded that an apparent violation of 10 CFR 50.59 had occurred. The violation was licensee-identified and was promptly addressed and corrected.

III. Engineering

E1 Conduct of Engineering

E1.1 Design Change Processes

a. Inspection Scope (37550)

The inspectors reviewed the procedures listed below which control design and design changes to determine if the procedure implement the requirements of 10 CFR 50, Appendix B, Criterion III and 10 CFR 50.59. The following procedures were reviewed:

EGR-NGGC-0001, Conduct of Engineering Operations, Revision 2, dated February 3, 1997

EGR-NGGC-0003, Design Review Requirements, Revision 0, dated June 3, 1996

EGR-NGGC-0005, Engineering Service Requests, Revision 4, dated March 25, 1997

EGR-NGGC-0006, Vendor Manual Program, Revision 1, dated August 6, 1996

EGR-NGGC-0007, Maintenance of Design Documents, Revision 0, dated December 17, 1996

EGR-NGGC-0156, Environmental Qualification of Electrical Equipment Important to Safety, Revision 0, dated March 5, 1997

EGR-NGGC-0320, Civil/Structural Operability Reviews, Revision 0, dated May 8, 1996

EGR-NGGC-0351, Performance Monitoring of Structures and Tanks, Revision 3, dated March 17, 1997

ENP-011, Preparation and Control of Design Analyses and Calculations, Revision 5, dated December 19, 1996

b. Observations and Findings

The inspectors verified that the procedures adequately addressed design inputs, design calculations, design verification, drawing changes, post-modification testing, control of field changes, 10 CFR 50.59 safety evaluations, training, and ALARA reviews.

The inspectors verified that Revision 4 of procedure EGR-NGGC-0005 complied with the design verification requirements of 10 CFR 50, Appendix B, Criterion III. This procedure is a corporate procedure which specified the requirements for preparation of design changes at the Brunswick, Harris, and Robinson plants. The inspectors identified a violation at the licensee's Brunswick Plant (see NRC Inspection Report number 50-325, 324/97-02) because Revision 3 and previous editions of procedure EGR-NGGC-0005 did not comply with the design verification requirements of 10 CFR 50, Appendix B, Criterion III. The violation is summarized as follows.

The engineering service requests (ESR) is the process used for performing engineering work. EGR-NGGC-0005 defines three types of ESRs. These are design change (DC), configuration change (CC), and engineering disposition (ED) ESRs. Design change ESRs were defined as a change which affects the design input of a system, structure, or component (SSC); while a configuration change was a change to a SSC which did not change the design inputs. Both of these ESRs produced design output documents which could have resulted in modifications to a SSC. Engineering disposition ESRs were used to supply information and do not produce design output documents or change any SSC. ESRs designated as design change ESRs required design verification to meet the requirements of 10 CFR 50 Appendix B, Criterion III, ANSI N45.2.11, and Regulatory Guide 1.64. The qualifications for design verifiers were addressed in paragraph 4.9 of EGR-NGGC-0001. ESRs designated as configuration changes required an engineering review, instead of a design verification. There were no specific requirements listed for individuals who performed the engineering review. The engineering review, as defined by CP&L procedure EGR-NGGC-0003 did not meet the in-

depth review and independent review requirements of Appendix B, Criterion III, ANSI N45.2.11, and Regulatory Guide 1.64. These requirements specify that the design control measures, including design verification activities, be established to assure the design basis is correctly translated into design outputs (e.g., drawings, specifications, procedures, and/or instructions). The requirements also specify that design changes be subjected to the same controls as those applied to the original design.

On February 11, 1997, as a result of the identification of this concern at the Brunswick Nuclear Plant, the licensee issued a temporary change to procedure EGR-NGGC-0005 which implemented the NRC requirements for design verification of safety-related ESRs. This temporary change included provisions for all in-process and non-field-complete configuration change ESRs to receive design verifications prior to their next approval step. The licensee issued CR 97-01255 on March 25, 1997, to document and disposition this problem at the Harris plant. In addition to revising procedure EGR-NGGC-0005, the licensee's corrective actions, which were in progress during the inspection, also included review of all safety-related configuration change ESRs to determine if an appropriate design verification was performed.

Use of Revisions 0 through 3 of EGR-NGGC-0005 to control design activities and failing to perform design verification of safety-related ESRs was identified as a violation of 10 CFR 50, Appendix B, Criterion III. This violation is considered licensee-identified at the Harris facility because plant personnel took immediate action to resolve the issue once it was identified as a violation at another facility. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-400/97-04-05, ESR Design Verification Requirements).

c. Conclusions

The inspectors concluded that the licensee's current design change control procedures complied with the requirements of 10 CFR 50.59, and 10 CFR 50, Appendix B, Criterion III. However, a non-cited violation was identified for failure to perform design verification of safety-related configuration change ESRs from June 3, 1996, the effective date of Revision 0 of EGR-NGGC-0005, through February 11, 1997, when NRC identified that EGR-NGGC-0005 did not comply with 10 CFR 50, Appendix B, Criterion III at the Brunswick Plant.

E1.2 Review of Modifications to Electrical Systems

a. Inspection Scope (37550)

The inspectors performed a review of modifications planned for refueling outage (RFO) 7, with a concentration on electrical systems. There were 18 modification packages prepared for implementation on electrical systems: eight "safety-related", seven considered important to safety by

the inspector, and the remainder nonsafety-related. Some of the requirements applicable to the areas of review were 10 CFR 50, Appendix B, 10 CFR 50.59, 10 CFR 50.71 and FSAR Sections 7 and 8.

Each of the 18 modifications was discussed with the cognizant engineer. For several modifications, specific additional information was requested and evaluated by the inspectors.

b. Findings and Observations

Each of the engineers contacted were knowledgeable of their assigned modification, the technical issues involved and the relevant requirements. No problems were identified with the design control program or process. The inspectors observed an effectiveness in resolving safety issues and maintaining the design basis as evidenced by the following examples:

- The ground detection system for the safety-related batteries was upgraded (this was actually an on-line modification).
- Root cause evaluations for circuit breaker problems were good.
- Modifications in the switchyard under the control of the transmission group (i.e., non-plant personnel) were treated as a plant modification for purposes of performing 50.59 evaluations.

During observation of work in progress, the inspectors noted a problem with modification ESR 9500233, Telemecanique Disconnect Switch Obsolete. This modification replaced a number of fused disconnect switches with ones from a different manufacturer. The dimensions provided in the installation instructions were incorrect which resulted in work stoppage to revise the dimensions. This one example of apparently not verifying through walkdowns or mockups the accuracy of work instructions was considered an isolated case.

c. Conclusions

Based on a review of modifications to electrical systems implemented in the current refuel cycle, the licensee's performance in the area of design control and compliance with the requirements stated in the inspection scope section was good.

E1.3 Permanent Cavity Seal Installation

a. Inspection Scope (37550)

The inspectors reviewed drawing and procedures for installation of a permanent cavity seal.

b. Observation and Findings

The inspectors reviewed ESR 94-00013, Permanent Cavity Seal Ring. The purpose of this modification was to eliminate the need for installation of a temporary seal each refueling outage which used a pneumatic seal with caulking (RTD) materials to enable flooding of the reactor cavity for refueling operations. This modification was originally scheduled for installation during RFO-6, but fit-up problems resulted in rework of the permanent seal components and delayed installation until RFO-7. The inspectors reviewed procedure EPT-219T, Revision 4, Permanent Cavity Seal Ring Installation which contained requirements for the seal installation. This procedure specified prerequisites, installation procedures, QC inspection requirements, and acceptance testing of the completed installation. Acceptance testing included hatch cover leak testing, pre-floodup inspection, and the floodup inspections for leaks. The procedures also specified requirements for visual inspection and non-destructive examination (dye penetrant testing) of welds. The inspectors reviewed vendor drawing numbers 6445E71 through 6445E74, and 6445E76 and vendor technical manual MSE-REE-725 which specified the installation details. The inspectors noted that problems identified during RFO 6 had been resolved.

c. Conclusions

The inspectors concluded that the installation documents were adequate to assure proper installation of the new permanent cavity seal. The acceptance testing specified was adequate to assure the seal would perform its intended function.

E1.4 Walkdown Inspection of Reactor Containment Building

a. Inspection Scope (37550)

The inspector performed a walkdown inspection of the containment building to examine the condition of the structure and installed systems.

b. Findings and Observations

The inspectors, accompanied by two engineers from the Nuclear Assessment Section (NAS), walked down the containment building on elevations 221 (feet above sea level), 236, 261, and 286 and examined the containment structure, pipe supports, instrumentation and cable tray supports and the condition of protective coatings. During the walkdown, the inspector identified some areas where the liner plate appeared to be corroded at elevation 221 from azimuth 60 through 120° adjacent to the concrete slab.. Some small areas with corrosion were also identified adjacent to the sumps, and the silicone expansion joint sealer was separated from the liner plate in some areas. The purpose of the silicon seal was to keep

moisture out of the one inch wide Ethafoam expansion joint between the liner plate and five foot thick concrete base slab inside containment. The licensee initiated CR 97-01880 to document and disposition this problem. The licensee removed the corrosion and perform NDE (ultrasonic testing) to determine if the corrosion had reduced the thickness of the liner plate. The UT showed that the liner plate exceeded the nominal thickness of 0.375 inches. The licensee removed portions of the silicon seal and the expansion joint material (one inch thickness of ethafoam) and examined the liner visually and with UT. The inspectors witnessed the UT exams and concurred with the licensee's testing methods and test results which showed that the liner exceeded 0.375 inches (section M2.6). The results were documented and evaluated in ESR 97-00359. During the visual exams, licensee engineers determined that the expansion joint gap was filled with water up to elevation 219.5. This was the same elevation as the water level in the containment sumps. The licensee pumped the water from the expansion joint, pumping out in excess of 5000 gallons. Chemical analysis of the water showed a pH of 6.8, and a boron concentration of 2700 ppm. The licensee concluded that the apparent source of water in the expansion joint was from the sumps. The licensee repaired the coatings on the liner, repaired seals between the expansion joint and sumps, and installed a system to monitor the water level during plant operations. The licensee plans to complete long term corrective actions (discussed in ESR 97-00359) during the next refueling outage.

c. Conclusions

Plant engineers conducted a good indepth evaluation of this problem after it was identified by the inspectors.

E2 Engineering Support of Facilities and Equipment

E2.1 General Comments (37551)

The licensee's root cause investigation into the second reactor coolant system boron dilution event discussed in report section O4.2 uncovered several previous engineering problems. These included incomplete update of vendor information related to the new valve coefficient for the boric acid flow control valve (1FCV-113A) after its internals were replaced in the mid-1980s. Also, incorrect assumptions were made about the capability of 1FCV-113A when RCS boron concentration requirements were increased after a plant upgrade to a higher enrichment of nuclear fuel in 1992. The valve was never tested to verify that its flow capacity would support the new higher boron concentration requirements. After repeated problems with flow deviation alarms due to inadequate boric acid flow through the valve, a Plant Change Request (PCR 7285) was issued to change the valve trim. This PCR was subsequently canceled in 1995 for no apparent reason.

As mentioned in report section 04.2, the above engineering problems all contributed to the system malfunctions that ultimately lead to the April 8, 1997 boron dilution event identified as example 3 to Violation 50-400/97-04-02. The licensee's root cause investigation into the engineering issues related to the April 8 event was thorough. The FCV-113A valve trim was replaced during RFO-7 and was being tested subsequent to this inspection period.

E2.2 Engineering Review of NRC Information Notices

a. Inspection Scope (40500)

The inspectors reviewed the licensee's system for processing and evaluating NRC information notices.

b. Observations and Findings

The inspectors reviewed CP&L procedure number AP-31, Operating Experience Feedback, Revision 5, dated February 1, 1996. This procedure specifies the process for review and evaluation of NRC information notices (INs) and other operating experience documents. The inspectors also discussed the licensee's system for review and evaluation of INs with licensing engineers and reviewed the status of recently issued INs. The review and discussions disclosed that with the exception of IN 97-09 through 97-13, all other INs has been reviewed in licensing and forwarded to the appropriate group (engineering, operations, maintenance, etc) for evaluation. IN 97-09, dated March 12, 1997, through IN 97-13, dated March 24, 1997, had not yet been processed by licensing and forwarded to engineering due to the recent retirement of the individual in licensing who previously was responsible for processing the INs. These INs were forwarded to engineering for evaluation. An ESR was opened to document Engineering actions to address the issues in individual INs. Additional documents are issued as required to initiate appropriate actions to resolve any identified issues. A recent assessment, number H-SP-97-05, completed on April 1, 1997, by the Nuclear Assessment Section (NAS) identified an issue regarding some discrepancies in procedure AP-31. The licensee issued CR 97-01423 to document this finding. The procedure will be revised as necessary to address the discrepancies. An item for management consideration was also identified by NAS regarding the fact that the computer database used to track operating experience items was not "user friendly."

The inspectors questioned licensee engineers regarding their plans for followup on IN 97-10, Liner Plate Corrosion in Concrete Containments. Since this IN had not yet been sent to engineering, no specific actions had yet been developed to address the IN. However discussions with the containment engineer disclosed that the licensee was in the process of implementing the requirements to comply with revisions to 10 CFR 50.55a which requires

containment inspections and repairs be performed in accordance with ASME Section XI, Subsections IWE and IWL. This inspection was scheduled to be performed prior to the containment leak rate test, approximately three days after the inspectors completed the containment walkdowns discussed in paragraph E1, above.

c. Conclusion

The inspectors determined that the licensee has established acceptable procedures for the review and evaluation of NRC information notices.

E2.3 Foreign Material Found in B CCW Heat Exchanger

a. Inspection Scope (40500)

The inspectors reviewed the licensee's evaluations and resolution of foreign material found in B CCW Heat Exchanger.

b. Observations and Findings

During the licensee's inspection of the "B" component cooling water (CCW) heat exchanger, foreign materials were found. The source of the materials was determined to be from the emergency service water strainers that failed due to corrosion. The purpose of the strainers was to filter the service water and prevent materials from being introduced into the system. The licensee initiated CR 97-01661 to document and disposition this problem.

Inspection of the "A" train ESW pump strainers disclosed that these strainers, which were the original materials, were still functional. The "B" train pump strainers were replaced during RFO 6. The original strainers were fabricated from 304 stainless steel. The replacement strainers were made of Monel 400. The inspectors reviewed Material Evaluation Report number 001394.00 which was prepared to evaluate the replacement strainers. The substitution of Monel 400 for 304 stainless was considered a material upgrade since the monel is more corrosion resistant than 304 stainless. The monel was selected due to the unavailability of new stainless steel strainers. The material evaluation report showed that the monel was acceptable. The cause of the failure was still under investigation by licensee materials engineers.

The licensee decided to replace the failed monel strainers with new strainers fabricated from 304 stainless since this was the material originally specified, and the service life of the 304 strainers was satisfactory in the "A" pumps. The inspectors reviewed Material Evaluation number 002703.00 which was completed to obtain replacement strainers for the failed Monel strainers from another utility. Replacement strainers were not available from the vendor. Documentation supplied by the original vendor indicated that the replacement strainers had been fabricated from

304 stainless. However, upon receipt inspection and testing performed by the licensee when the new strainers were received at the Harris site, the licensee determined that some of the strainers had been fabricated from 316 stainless. A material hold was placed on the strainers pending further investigation by procurement engineering.

Procurement and receiving activities were handled under the CP&L corporate Operations and Environmental Support Department's Materials Services Section, designated as Procurement Engineering. This is a separate organization from the Harris Engineering Services Section and the corporate Nuclear Engineering Department. The following documents were reviewed which specified requirements for procurement, evaluation and selection, and receiving inspection of plant components:

- MCP-NGGC-0401, Material Acquisition, Rev. 2, dated April 15, 1997.
- EGR-NGGC-0204, Evaluation and Selection of Materials for Plant Components, Rev. 0, dated December 6, 1996.
- Procurement/Design Engineering Interface Agreement, dated January 5, 1996.

The inspectors concluded that the licensee's controls for procurement of replacement hardware complied with NRC requirements. The cause of the corrosion of the monel strainers in the "B" ESW pump was still under investigation at the end of the inspection period.

c. Conclusions

The inspectors concluded that the failure of the strainers in the "B" ESW train were not related to an inadequate evaluation for the replacement strainers. The licensee's procurement engineering program meets NRC requirements. Licensee engineers were very proactive in the evaluation of the strainers' failure.

E7 Quality Assurance in Engineering Activities

E7.1 Special FSAR Review (37551)

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the FSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the FSAR that related to the areas inspected.

The licensee made a presentation to the NRC on May 31, 1996 concerning their corporate-wide plan for reviewing the FSAR at the CP&L sites. The program has generated a large number of condition reports at the Harris Plant (311 by the end of the inspection period). The results from this program will be reviewed in the closure of Unresolved Item 50-400/96-04-04, Tracking FSAR Discrepancy Resolution. The inspectors did not find any additional discrepancies other than those identified by the licensee.

E7.2 Quality Assurance Assessment and Oversight

a. Inspection Scope (40500)

The inspectors reviewed self-assessments performed within the Harris Engineering Support Section.

b. Observations and Findings

Self-assessments are part of the overall CP&L quality assurance program at Harris. The self-assessments were performed in accordance with procedure PLP-03, Self-Assessment, Revisions 4 and 5. The results of these assessments were categorized as strengths, or findings. The following self-assessments were reviewed by the inspector:

- HESS 96-016, EQ Program, May 6 - 9, 1996,
- HESS 96-025, Procedure compliance - Corrective Action Effectiveness, October 1 - November 22, 1996,
- HESS 96-028, Service Water Program, and
- HESS 97-002, EDBS Program, January, 1997.

Several findings were identified in Assessment 96-016. Six Condition Reports (CRs) were written to document discrepancies identified in the EQ program. However none of the problems resulted in identification of any inoperable equipment. The conclusion of the assessment was that the Harris EQ program meets overall requirements. The issues identified primarily involved procedural discrepancies which were being addressed through issuance of new procedures. A corporate procedure, NGGC-EGR-0156 was recently issued to resolve some of the discrepancies and clarify some of the EQ requirements. One weakness and two issues for management consideration were identified in Self-assessment 96-028. The weakness involved lack of acceptance criteria in a service water surveillance test procedure. The areas for management consideration involved procedural issues. A CR was opened to address the weakness and areas for management consideration. Five issues and two items for management consideration were identified in self-assessment 97-002. Condition reports were initiated to document and resolve these problems. The primary areas of concern identified by the self-assessment involved inadequate controls in procedures. Corrective actions were in progress at the end of the inspection period.

c. Conclusions

The inspectors concluded that the self-assessments performed by HESS were effective in identifying engineering performance deficiencies and were useful in providing oversight to management. Managers in HESS have been proactive in following up on the EQ problems identified at other sites to address any EQ program deficiencies.

E8 Miscellaneous Engineering Issues (92700, 92903)

E8.1 (Closed) Unresolved Item 50-400/96-02-03: Use of Potentially Unconfirmed Information Obtained via Telecons in Design Calculations.

During review of engineering service requests during the inspection documented in NRC Inspection Report 50-400/96-02, the inspectors identified three examples of licensee design engineers' apparent use of information obtained from vendors over the telephone without proper verification of the accuracy of the information. This issue was originally identified during NAS Assessment H-MOD-94-01. The examples were identified in ESR numbers 9400076, 9400118, and 9500120. Further review of the ESRs disclosed that additional information was available in the design backup section of the ESR which showed the vendor provided additional data to confirm the information originally provided in the telecon. The inspectors reviewed the additional information provided by the licensee and verified that the telecon data was properly documented. In one case, ESR 9400118, the telecon information was used to develop the ESR. The ESR was then sent to the vendor for concurrence. Licensee engineers reviewed design change packages installed during the previous three refueling outages, RFO-4, 5, and 6, and determined that no other examples were identified of the use of information obtained in telecons with vendors for design information with the exception of the example identified by NAS. Precautions regarding the use of vendor supplied design inputs were discussed in CP&L procedure numbers EGR-NGGC-0005 and 0006. This issue was also discussed with engineering personnel during training. The inspectors also verified during review of the ESRs listed in paragraph E1 above that unconfirmed information was not used in preparation of design documents. This item is closed.

E8.2 (Open) URI 50-400/96-04-04: Tracking FSAR Discrepancy Resolution (Spent Fuel Pool Cooling).

An initial review of the spent fuel pool cooling system based on problems at another facility resulted in the opening of IFI 50-400/96-02-04. This item was later closed and converted to this unresolved item based on the licensee's FSAR review program. The NRC completed a generic licensing review of spent fuel pool safety issues and by letter dated July 1, 1996 and September 17, 1996, transmitted the results to the licensee. The licensee responded to the July 1, 1996 letter on

August 8, 1996 and committed to updating the current spent fuel pool heat load analysis, updating the FSAR to clarify the terms abnormal and normal fuel off-loads, and revising the FSAR to reflect the current installed spent fuel pool configuration.

The inspectors found that the FSAR change (RAF 2295) was approved March 12, 1997. The inspectors reviewed the FSAR change and associated safety evaluation (per 10 CFR 50.59) and found that the commitments were completed prior to core off-load. The heat load analysis was updated to reflect the latest calculation. The FSAR was clarified to remove the words "abnormal" and "normal" off-load, replacing them with "full core offload shuffle" and "post outage full core offload". The FSAR was revised to reflect the current spent fuel pool cooling configuration and latest description of equipment, since the equipment originally described in the FSAR that supported the unit 2 spent fuel pools have not been completely installed. This item remains open pending the licensee's completion of their overall FSAR review program.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Radiological Controls

a. Inspection Scope (83750)

The inspectors evaluated radiological controls with emphasis on external occupational exposures during outage conditions. Areas inspected included controls for locked high and very high radiation areas, radiation area postings, radiation work permits (RWPs), and controls for radioactive material in accordance with the requirements of 10 CFR 20.

b. Observations and Findings

The inspectors made frequent tours of the radiation controlled area (RCA), observed personnel compliance with radiation protection procedures for high dose work evolutions, and conducted interviews with licensee personnel to ascertain knowledge of radiological controls and working conditions. The inspectors verified controls for external and internal exposures met applicable regulatory requirements and were designed to maintain exposures as low as reasonably achievable (ALARA). The inspectors reviewed select RWPs which controlled ongoing outage work within the RCA, including high dose activities within containment, and noted that the controls observed were appropriate for the described tasks and radiological conditions.

During plant walkdowns within the RCA, the inspectors conducted interviews at random with radiation workers both inside and outside of containment. The interviews were conducted with radiation workers of various disciplines in order to determine the level of understanding of RWP requirements from a representative cross-section of plant workers.

All of the workers interviewed were verified to have signed onto an RWP, were wearing dosimetry appropriate to their work activities and in accordance with their RWP, and were performing specific work activities permitted within the scope of their specific RWP. The workers, by signing onto an RWP via the access control computer, signified that they understood the conditions and requirements of the RWP being logged onto in accordance with Environmental and Radiation Control (E&RC) procedures. The questions asked included the RWP number of the RWP signed onto, dosimetry alarm and cumulative dose limits, available dose remaining, and general radiological working conditions for the areas worked in. The workers demonstrated generally good knowledge of RWP requirements and radiological working conditions.

The inspectors reviewed total whole body exposures for all licensee radiation workers and determined that all whole body exposures assigned during 1996 and 1997 through the end date of inspection were within 10 CFR 20 regulatory limits. A review of licensee personnel exposure records indicated the following maximum individual exposures at the plant during 1996 were: Total Effective Dose Equivalent (TEDE): 795 mrem and Shallow Dose Equivalent (SDE): 5660 mrem from a hot particle. No internal exposures were reported for the period. Through March 1997, the licensee incurred a maximum TEDE of 115 mrem with no contamination events that exceeded the SDE threshold requiring a dose assessment. The inspectors determined the licensee had adequately monitored and tracked individual occupational radiation exposures in accordance with 10 CFR Part 20 requirements and that all doses reported were at a small percentage of applicable regulatory limits.

The inspectors evaluated the licensee's program for controlling access to high radiation areas (HRAs) and locked high radiation areas (LHRAs). These areas were inspected during tours for proper postings and access controls. No HRAs or LHRAs were identified where required postings were needed but not posted. Areas controlled as LHRAs were inspected and found locked or otherwise controlled in accordance with licensee procedures. The licensee had completed a posting upgrade with respect to radiation areas to achieve full compliance with the regulatory intent of 10 CFR 20.1902.

Key controls for entry into locked high radiation areas were evaluated against the requirements of the licensee's administrative procedure and determined to be appropriate. During a tour of the spent fuel building, the inspectors observed no items hanging from the side of the pool that were not labelled or properly controlled in accordance with procedure. Good radiological controls were observed to be in place in the entire spent fuel building. A sample of survey instruments available for issuance was inspected and determined to have current calibration dates and be in operable condition. Radiation workers were observed exiting the RCA during peak traffic periods in accordance with procedures for frisking out of the RCA.

c. Conclusions

The radiological controls program in general was being effectively implemented with good radiation control performance demonstrated during the refueling outage.

R1.2 Radiation Work Permit (RWP) Doses Exceeded

a. Inspection Scope (83750)

The inspector reviewed circumstances surrounding a licensee-identified RWP dose limit violation that occurred on April 12, 1997.

b. Observations and Findings

During the removal and replacement of insulation from the chemical and volume control system regenerative heat exchanger on the 236-foot elevation of the reactor containment building, a Radiation Control (RC) Technician and an insulation contractor each exceeded their RWP-allowed doses of 400 mrem. This occurred when both individuals failed to immediately exit their work area when their electronic dosimeters alarmed at the accumulated dose setpoint of 320 mrem. Doses received by the RC Technician and the insulator during the entry were 530 mrem and 495 mrem, respectively. The individuals indicated in written statements they did not hear their electronic dosimeters' initial alarms due to high noise levels in the work area and only became aware they had exceeded their RWP limits when they came out to undress.

Based on the inspector's review of the workers' statements, radiation control oversight was inadequate in that the RC Technician providing health physics (HP) job coverage actively participated in the insulation work in order to expedite job completion and lost focus on the primary assigned role of radiation control. Although no administrative or regulatory dose limits were exceeded during the incident, the failure of the workers to promptly exit the work area when their electronic dosimeters alarmed is a violation of Administrative Procedure AP-535, Revision 8, Section 5.16.5, Performing Work in Radiation Control Areas, which required workers to immediately leave a work area when an electronic dosimeter is in alarm. The licensee took prompt and thorough action in response to the incident to include assigning a significant Level 1 Condition Report which will require an in-depth root cause analysis, expedited completion of required corrective actions, counselling and discipline with respect to the workers involved, and a stand-down meeting with all site HP personnel to increase emphasis on the need for strict compliance with RWP requirements and safe radiation worker practices. This licensee-identified and corrected violation is being treated as a Non-Cited Violation consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-400/97-04-06).

c. Conclusions

One Non-Cited Violation was identified for failure of radiation workers to promptly leave a work area when their electronic dosimeters alarmed.

R1.3 Inadequate Labeling of Radioactive Material

a. Inspection Scope (83750)

The inspector performed routine walkdowns inside the RCA on April 14-15, 1997, to verify that radioactive material was tagged and labeled in accordance with licensee procedures.

b. Observations and Findings

The inspector identified examples of radioactive material that were not tagged and labeled in accordance with licensee procedures. The inspectors surveyed miscellaneous hand tools and scrap metal pieces that were found in an unmarked five gallon bucket located in the vicinity of the bead-blast unit on the 236-foot elevation of the waste processing building. The inspectors identified a hand chisel with fixed contamination levels which required marking per procedure or controlled as radioactive material and tagged (greater than 100 net counts per minute). Upon the inspector's request, licensee personnel frisked the remaining unmarked/untagged materials in the bucket and found additional items not controlled in accordance with procedure HAS-NGGC-0003. Another example was identified by the inspectors on the 291-foot elevation of the same building where a bag of wrapped lead shielding was not tagged properly as radioactive material. All of the items identified were judged to be of minimal safety risk due to the low radiation levels detected.

The failure of the licensee to label the radioactive materials with a clearly visible label bearing the radiation symbol and the words "Caution, Radioactive Material" is contrary to licensee procedure HPS-NGGC-0003, Revision 1, Paragraph 9.2, Tagging and Labeling of Radioactive Material which requires each container holding radioactive material to be so-labeled. Additionally, in accordance with the same procedure and paragraph, hand tools with fixed contamination greater than 100 net counts per minute are required to be marked with purple or magenta paint. Based on the relatively isolated nature of the items identified, the licensee's prompt and thorough corrective actions, and the relatively low safety significance of the radiation hazard, this failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy (NCV 50-400/97-04-07).

c. Conclusions

One Non-Cited Violation was identified for failing to tag and label radioactive material in accordance with procedure.

R1.4 Contamination Controls

a. Inspection Scope (83750)

The inspectors evaluated the licensee's controls for personnel contamination events (PCEs) and adequacy of related PCE followup. Also evaluated was the adequacy of contamination surveys and contaminated area controls.

b. Observations and Findings

The inspectors reviewed the records of all PCEs incurred during 1996 and 1997 through the date of inspection. During 1996, the site incurred 41 PCEs which was well within the licensee's 1996 annual goal of 50 PCEs. Based on the history of PCEs at the site, the inspectors determined that the original PCE goal was aggressive based on prior PCE performance. During 1995 and 1994, periods with outage activity, the licensee experienced 177 and 226 PCEs, respectively. Although the number of PCEs incurred is a minor radiation safety concern, PCEs reflect on the effectiveness of a licensee's contamination control program and on radiation work practices. During an evaluation of 1996 PCEs, the inspectors noted that each contamination event was evaluated by the licensee in accordance with PCE procedure with corrective actions taken in each case, as appropriate. Only 5 of the 41 PCEs in 1996 were skin contaminations and only 2 of these contaminations resulted in a SDE dose greater than the 100 mrem threshold requiring full dose assessment. Within the total 41 PCEs in 1996, 18 resulted from work in designated clean areas which is a high proportion representing a challenge area for the licensee. The inspectors reviewed the PCE evaluations and noted no assessment or procedural errors. The inspectors verified skin dose assessments had been performed with conservative dose assessment methodology utilized. Overall, licensee actions with respect to improving personnel contamination controls were determined to be effective with no regulatory concerns noted.

During 1996, the licensee achieved a monthly average of 4183 square feet of recoverable contaminated floor area which was well within the 1996 goal of 4600 square feet. This goal represents approximately 1 percent of the RCA area which is relatively low. The equivalent monthly average for 1995 was 6362 square feet. During the first three months of 1997, the licensee was able to achieve a monthly average of 3324 square feet prior to the RFO-7 outage. The licensee effectively reduced contaminated square footage by tracking performance goals for each building, eliminating contributors to contamination, and continued decontamination of recoverable areas. Overall, contaminated areas were being maintained to less than one percent of total RCA square footage which represents good performance in this area. The inspectors reviewed documented contamination surveys performed during the ongoing refueling outage and observed HP technicians performing contamination surveys in accordance with procedure. Also, during inspection of the tool issuance rooms, good controls for slightly contaminated tools inside the RCA and for clean tools outside the RCA were noted.

c. Conclusions

Contamination control was effective overall with surface contamination controlled adequately at its source. The licensee continued to effectively reduce PCEs with adequate procedural followup on contamination events. Licensee initiatives to reduce contaminated square footage were effective in maintaining contaminated areas to less than one percent of the RCA.

R1.5 As Low As Reasonably Achievable (ALARA) Program Effectiveness

a. Inspection Scope (83750)

This area was evaluated to determine whether the licensee was establishing and tracking ALARA goals and to evaluate the overall effectiveness of the ALARA program. 10 CFR 20.1101(b) requires that the licensee use procedures and engineering controls based upon sound radiation protection principles to achieve occupational doses that are as low as reasonably achievable.

b. Observations and Findings

Collective personnel dose of 17.238 person rem for 1996 was a record low for the site for a non-outage year. During 1997, through the end of March, the licensee incurred 4.42 person-rem, which continued the low dose rate trend during periods of power operations experienced during 1996. Based on NUREG-0713 data, the licensee's dose performance ranks among the lowest doses for single unit PWR sites. A relatively large and unique dose contributor was that which occurred due to receipt and decontamination of Brunswick and Robinson spent fuel shipments. This dose accounted for approximately 28 percent of overall site dose during 1996. Another large non-recurrent dose contributor during 1996 was a material upgrade and painting project that resulted in 2.256 person-rem and represented a 13 percent dose contribution. Exclusive of non-recurrent dose, the licensee's effective dose rate in person-rem per thousand RWP hours was exceptionally low and indicative of an effective ALARA program.

The inspector reviewed implementation of the ALARA program with licensee representatives and noted that several initiatives to reduce overall dose were implemented in 1996 and more were underway or planned for 1997. During 1996 ALARA initiatives included: completed loop trainer for mock-up and scenario training; implemented advanced radworker training; developed list of satellite valves for maintenance planning; and initiated a radiological information tracking system for survey and job history records retrieval. Planned initiatives in 1997 include: fabricate a seal table mock up, installed permanent cavity seal ring, evaluate increased use of robotics, evaluate permanent shielding packages; and initiate study on use of sub-micron filtration.

c. Conclusions

The licensee's ALARA program was effectively controlling collective dose and collective dose was on a favorable reducing trend. Operational doses during 1996, a non-outage year, were at record lows for the plant.

P1 Conduct of EP Activities

P1.1 General Comments (71750, 93702)

The inspectors observed the licensee's activities for various challenges that involved the implementation of emergency preparedness procedures during the inspection period. These included two RCS boron dilution events, a bomb threat, and a small fire in the reactor auxiliary building. The inspectors concluded that emergency action level procedures were properly implemented by control room personnel during and following these occurrences. Communication between control room personnel and other involved organizations was adequate. Licensee personnel properly notified the NRC via the Emergency Notification System in accordance with 10 CFR 50.72 for the bomb threat. No Emergency Action Level declarations were required for the above events. No emergency preparedness drills were conducted during this period.

S1 Conduct of Security and Safeguards Activities

S1.1 General Comments (71750, 93702)

The inspectors observed security and safeguards activities during the conduct of tours and observation of maintenance activities, and found them to be good. Compensatory measures were posted when necessary and properly conducted. Security personnel's response to a bomb threat on May 8, 1997 was adequate. The bomb threat was determined to be non-credible. Offsite law enforcement agencies were notified and a four-hour report was made to the NRC in accordance with 10 CFR 50.72.

F1 Control of Fire Protection Activities

F1.1 General Comments (71750)

The inspectors observed fire protection equipment and activities during the conduct of tours and observation of maintenance activities and found them to be acceptable.

F1.2 Resolution of Thermo-Lag Fire Barrier Issue (64704)

a. Inspection Scope

The inspector reviewed the action taken to resolve the degraded Thermo-Lag fire barrier issue at Harris to determined if the licensee's action was consistent with commitments made to the NRC.

b. Observations and Findings

In 1991, the NRC identified that Thermo-Lag fire barrier material did not perform to the manufacturer's specifications. NRC Bulletin 92-01 "Failure of Thermo-Lag 330 Fire Barrier System to Maintain Cabling in Wide Cable Trays and Small Conduits Free from Fire Damage" was issued which requested licensees with Thermo-Lag fire barriers to consider these fire barriers to be degraded and take appropriate compensatory measures for the areas where the Thermo-Lag fire barriers were installed.

Initially, the plant had approximately 1,800 square feet of Thermo-Lag fire wall/ceiling configurations. This also included a partial height, one-hour rated fire wall and protection associated with fire door transoms and mullions. The fire wall/ceiling configurations are located in the Auxiliary Control Panel Room and Cable Spreading Rooms "A and B". The fire doors are located on various elevations in the Reactor Auxiliary Building (RAB).

The licensee has evaluated the results of data from various tests performed by the nuclear industry on Thermo-Lag fire barrier installations. In addition, the licensee has performed three full scale fire tests of plant Thermo-Lag configurations independent of industry fire test programs to document the acceptance of the tests against the as-found condition of the fire barriers. Also, seismic evaluations and testing has been completed on Thermo-Lag configurations.

The partial height, one-hour fire wall was redesigned and the Thermo-Lag material removed and replaced with an alternate gypsum board material. Engineering evaluations have been completed to address Thermo-Lag use on fire door transoms. Also, revisions to combustible loading calculations to reflect Thermo-Lag combustibility and ampacity derating evaluations have been completed.

A safe shutdown methodology re-analysis was performed to identify the components required for plant shutdown following an Appendix R fire. The re-analysis specified the separation to be provided between safe shutdown components to meet the separation requirements of 10 CFR 50, Appendix R, Section III.G. This separation was to be provided by rerouting several safe shutdown cables for source range instrumentation and reactor head vents to eliminate the need for Thermo-Lag protection.

As of the date of this inspection, the licensee had initiated the implementation of corrective actions for Thermo-Lag issues, except for the installation of Thermo-Lag sleeve upgrades (ESR 95-00715), corrective actions for a recently identified Thermo-Lag barrier deficiency (LER 50-400/97-06 discussed in report section F8.1), safe shutdown cable rerouting (ESR 95-00682), and completion of remaining engineering evaluations (ESR 95-00620). The licensee's LER 50-400/97-06 stated that the Thermo-Lag issue at Harris would be resolved by September 15, 1997.

c. Conclusions

The licensee has been proactive in the resolution of the Thermo-Lag issue at Harris.

F1.3 Fire Reports

a. Inspection Scope (64704)

The inspector reviewed the plant fire incident reports for 1996 and 1997, to assess maintenance related or material condition problems with plant systems and equipment that initiated fire events. The inspector verified that plant fire protection requirements were met in accordance with procedure FP-003, Fire Investigation Report, Revision 6, when fire related events occurred.

b. Observations and Findings

The fire incident reports indicated that there were two incidents of fire in 1996, and three fire events in 1997, which required fire brigade response. No significant fires had occurred during this period. There had been one minor fire event in the turbine building involving cutting or welding activities and one minor electrical fire involving the "A" battery room during the current refueling outage (section M2.4). Only three of the five fires had occurred within the plant protected area.

c. Conclusions

Good compliance with plant fire prevention procedures resulted in a low incident of fire within the plant protected area.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Operability of Fire Protection Facilities and Equipment (64704)

a. Inspection Scope

The inspector reviewed open Condition Reports (CRs) on fire protection components and operation's out-of-service logs for fire protection equipment to assess the licensee's performance for returning degraded fire protection components to service. In addition, walkdown inspections were made to assess the material condition of the plant's fire protection systems, equipment, and features.

b. Observations and Findings

As of May 6, 1997, there were approximately 40 fire protection related CRs in which the corrective actions had not been completed. Most of these involved minor program improvement items and did not affect the operability of fire protection components. All of these CRs were initiated in 1997 or late 1996. The inspector concluded that there was

no significant corrective action backlog associated with the fire protection program or components.

Also, as of May 6, 1997, there were approximately 22 degraded or inoperable fire protection components. Most of these items were related to degraded fire doors and the refueling outage which was in progress. For example, a number of fire barrier penetrations were open for passage of temporary cabling for outage activities and fire detection was removed from service due to maintenance work being performed.

The remaining degraded features were either in nonsafety-related areas or were minor discrepancies which did not affect the operability of the system or component. Most of these items, which had been degraded since late 1996, were fire doors. The inspector verified that appropriate compensatory measures had been implemented for the degraded components where required.

Routine general inspections of plant areas are conducted by plant operations personnel during operations rounds in accordance with the Plant Overview Program (POP) Generic Rounds Guidance, provided in Attachment 1 to procedure OMM-016, Operator Logs, Revision 10. Guidance for inspection of fire protection features and equipment include:

- Deficiencies in fire wraps, Thermo-lag, and penetrations
- Transient combustibles controlled and documented per AP-302, Fire Protection, Housekeeping, and Temporary Storage, Revision 6
- Hot work in progress controlled per FPP-005, Duties of a Firewatch, Revision 12; and FPP-006, Control of Ignition Sources - Hot Work Permits, Revision 16
- Trouble or alarm conditions on local fire detection control panels
- Fire system controls and actuation components in order
- Oily rag cans are emptied once per day (Day Shift)

The inspector toured the RAB on May 6, 1997, with the Senior Support Analyst in charge of Fire Protection and a plant Auxiliary Operator on rounds within the RAB. The inspector noted that the operator performed a thorough general inspection of the assigned areas in accordance with the fire protection guidelines provided in POP-6. Within the areas toured, the fire detection and suppression systems were well maintained and the material condition was good.

c. Conclusions

Based on the inspector's review of open Condition Reports (CRs) on fire protection components and inspection of the fire protection components, the inspector concluded that there was not a significant corrective action maintenance backlog associated with the fire protection systems.

In addition, the material condition of the fire protection components was good.

F2.2 Surveillance Procedures for Fire Protection Standpipe and Hose System

a. Inspection Scope (64704)

The inspector assessed the scope of the licensee's fire protection surveillance and tests identified in procedure FPP-014, Fire Protection - Surveillance Requirements, Revision 8, to determine compliance with FSAR Section 9.5.1, and Technical Specifications (TS).

b. Observations and Findings

The inspector reviewed FSAR Section 9.5.1.2.3, Fire Protection Standpipe and Hose System, which described the functional interface of the emergency service water system and the fire protection system to provide post-Safe Shutdown Earthquake (SSE) manual fire protection capability in areas required for safe plant shutdown. Valves included in this FSAR section were the seismically qualified check valves (numbered 3FP-180 and 186; and 1FP-205, 218, 2079 and 2080) designed to prevent backflow and outflow to other (non-seismically qualified) portions of the fire protection water distribution system which may fail during a seismic event. These check valves were intended to prevent the loss of ESW and maintain hose line protection after the earthquake. The inspector noted that no surveillance test procedures existed to verify that the check valves would perform their intended function.

Technical Specification 6.8.1.a and Regulatory Guide 1.33, Appendix A, Section 8.b.1.h, require written procedures for fire protection functional tests. The failure to provide fire protection surveillance procedures to verify the functionality of the seismically qualified fire protection check valves that provide fire protection and emergency service water system integrity (following a SSE) is considered a violation of TS 6.8.1.a (50-400/97-04-08).

c. Conclusion

A violation of Technical Specification 6.8.1.a was identified for failing to establish written procedures to verify the functionality of the seismically qualified fire protection check valves that provide fire protection and emergency service water (ESW) system integrity following an SSE. This condition had existed since plant commercial operation.

F2.3 Periodic Surveillance Testing of Fire Protection Features and Equipment

a. Inspection Scope (64704)

The inspectors reviewed the following completed surveillance tests:

- FPT-3560/F, 18 Month, Fire Wrap Inspection. Completed August 13, 1995.

- FPT-3002, Monthly, Fire Main Valve Position Verification. Completed April 4, 1997.

- FPT-3002, Monthly, Reactor Auxiliary Building Fire Hose Rack Inspection. Completed March 27, 1997.

The frequency of selected surveillance test procedures were also reviewed.

b. Observations and Findings

The surveillance tests reviewed by the inspectors had been appropriately completed and met the acceptance criteria. The test procedures were well written and met the fire protection surveillance requirements of FPP-014, Fire Protection Surveillance Requirements, Revision 8.

A review of the open scheduled surveillance tests for 1997, indicated that approximately 60 percent of the long-term (either quarterly, six-month, annually, or 18-month frequency) fire protection surveillance test procedures currently scheduled had not been completed and have been extended into the allowed grace period. The inspector considered the number of fire protection surveillances being performed in their grace period to be excessive. This issue was previously identified as a weakness (W1) in a licensee fire protection assessment, Nuclear Assessment Section Report H-FP-97-01, dated February 26, 1997. Licensee management was currently evaluating corrective actions to resolve this issue.

There did not appear to be a formal program for trending fire protection condition reports and performance of fire protection system testing. However, periodic informal interface between operations and engineering personnel assigned fire protection related functions was being made to coordinate the implementation of the fire protection program. The surveillance procedure test data for the capacity tests on the fire pumps and the diesel fire pump oil analysis data were reviewed by the plant system engineer. This data provided good verification of the pump's performance.

c. Conclusions

Implementation of the fire protection surveillance program has not been fully effective. As previously identified in licensee self assessments, the number of fire protection surveillance procedures being performed within their grace period continued to be excessive.

F3 Fire Protection Procedures and Documentation

a. Inspection Scope (64704)

The inspector evaluated the adequacy and implementation of the licensee's Fire Protection Program described in the FSAR and in Plant Operating Manual Fire Protection Procedure FPP-001, Fire Protection -

Conduct of Operations, Revision 16. In addition, a comparison was made of the program to selected NRC Safety Evaluation Reports which approved the station fire protection program. The inspector reviewed the following procedures for compliance with the NRC requirements and guidelines:

- FPP-001, Revision 16, Fire Protection - Conduct of Operations
- FPP-002, Revision 13, Fire Emergency
- FPP-003, Revision 7, Transient Combustibles Tracking
- FPP-005, Revision 12, Duties of a Fire Watch
- FPP-006, Revision 16, Control of Ignition Sources - Hot Work Permits
- FPP-012, Revision 2, Fire Pre-Plans
- FPP-013, Revision 16, Fire Protection - Minimum Requirements and Mitigating Actions
- FPP-014, Revision 8, Fire Protection - Surveillance Requirements
- FPP-016, Revision 4, Fire Protection and First Aid Team Training
- OMM-016, Revision 11, Operator Logs

Plant tours were also performed to assess procedure compliance.

b. Observations and Findings

The above procedures were the principle procedures issued to implement the facility's fire protection program. These procedures contained the requirements for program administration, controls over combustibles and ignition sources, fire brigade organization and training, and operability requirements for the fire protection systems and features. The procedures were well written and met the licensee's commitments to the NRC, except that no surveillance test procedures existed to verify the functionality of the seismically qualified fire protection check valves as discussed in section F2.2 of this report.

The pre-fire plans reviewed by the inspector were found to be satisfactory and properly addressed the fire potential, area location, means of fire brigade approach, fire protection equipment available, fire brigade action, special instructions and hazards to be considered, operational safe shutdown considerations, and communications available.

A general plant walkdown inspection was performed by the inspector to verify acceptable housekeeping; compliance with the plant's fire prevention procedures such as "Hot Work" permits and transient combustibles; operability of the fire detection and suppression systems; emergency lighting; and installation and operability of fire barriers, fire stops, and penetration seals (used on fire doors, dampers, and electrical penetrations).

Within the areas observed, the inspector determined that general housekeeping was satisfactory, considering that the unit was in an extended outage and major maintenance and repair activities had been ongoing. The majority of storage pallets used during outage activities were noncombustible and constructed of metal. Fire retardant plastic

sheeting and film materials were also being used. Lubricants and oils were properly stored in approved safety containers. Appropriate controls for cutting and welding operations were being enforced. Controls were being maintained for transient combustibles and areas containing potential lubrication oil and diesel fuel leaks, such as the diesel generator rooms.

No discrepancies were noted with the outside fire hose houses, fire main valves or headers. However, the inspector noted two isolated bent sprinkler head deflector plates in the reactor auxiliary building sprinkler piping. Operability of the sprinkler system was not impacted by the bent deflectors since other overlapping sprinklers installed nearby were not affected. The licensee issued Deficiency Log Entry No. 97-D01184 to identify the problem and initiate corrective actions. Corrective actions in this area will be reviewed during future NRC inspections.

c. Conclusions

Except for the large number of fire protection surveillance test procedures being performed in the grace period, the fire protection program implementing procedures were good and met licensee and NRC requirements. The fire fighting pre-fire plans were satisfactory. Appropriate fire prevention controls were being applied to refueling outage activities.

F5 Fire Protection Staff Training and Qualification

a. Inspection Scope (64704)

The inspectors reviewed the fire brigade organization and training program for compliance with the NRC guidelines and requirements.

b. Observations and Findings

The organization and training requirements for the plant fire brigade were established by FPP-016, Revision 4, Fire Protection and First Aid Team Training. The fire brigade for each shift was composed of a fire brigade leader and at least four additional brigade members. As of the date of this inspection, there were a total of 72 trained fire brigade members of which 39 were from Operations, 21 from Environmental and Radiation Control (E&RC), and 11 from Maintenance. The fire brigade leader was a senior reactor operator. The other members from Operations were non-licensed plant operators. The inspector verified that sufficient shift personnel were available to staff each shift's fire brigade with at least five qualified fire brigade members.

Each fire brigade member was required to receive initial, quarterly and annual fire fighting related training and to satisfactorily complete an annual medical evaluation and certification by a physician for participation in fire brigade fire fighting activities. In addition, each member was required to participate in at least two drills per year.

Due to the unit being in an outage and the high priority work in progress, a fire brigade drill was not conducted during this inspection.

c. Conclusions

The fire brigade organization and training met the requirements of the site procedures.

F7 Quality Assurance in Fire Protection Activities

a. Inspection Scope (64704)

The following audit report and the plant response to the issues were reviewed:

- Assessment H-FP-97-01 Harris Annual Fire Protection Assessment, File No.: HNAS 97-011
- Response to Nuclear Assessment Section Report H-FP-97-01, File No. MS-970432

b. Observations and Findings

The licensee's Nuclear Assessment Section (NAS) performed a two week assessment of fire protection on January 13 through 24, 1997. The report for this assessment (Report No. H-FP-97-01) was issued on January 29, 1997. Findings from these assessments were categorized as strengths, issues, or weaknesses.

The inspector reviewed the final report and the licensee response to the identified issues, dated February 26, 1997. The assessment report identified two issues and three weaknesses. The issues identified by the NAS assessment included problems with fire brigade training and drill schedules (Issue I1) and engineering design controls associated with a design modification that degraded fire protection in the Waste Processing Building (I2). The weaknesses identified included insufficient management oversight and self-assessment of the fire protection program (Weakness W1); excessive number of fire protection surveillance procedures being performed in their grace period (W1); declining material condition of plant fire doors (W2); and problems with various types of emergency lighting (W3). The weaknesses identified in the assessment were in close agreement with problems noted during this inspection and licensee identified findings such as LERs, CRs, etc.

Planned corrective actions in response to the two identified issues were addressed in the line organization's response and were acceptable. Action on the three weaknesses which were identified to enhance the fire protection program were not addressed in the line organization's response to NAS. Comprehensive resolution of the weaknesses of the NAS assessment should provide significant improvement in the implementation of the fire protection program at this facility.

c. Conclusions

The 1997 assessment of the facility's fire protection program was comprehensive and was effective in identifying fire protection program performance deficiencies to management. Planned corrective actions in response to the audit issues were acceptable. The weaknesses identified in the assessment were in close agreement with problems noted during this inspection and licensee identified findings such as LERs, CRs, etc.

F8 Miscellaneous Fire Protection Issues (92700)

F8.1 (Open) LER 50-400/97-006-00: Breach in Reactor Auxiliary Building 3-hour rated fire barrier (Thermo-lag wall in Cable Spread Room).

This LER described a breach in the Thermo-Lag fire barrier wall which separated the "A" train and "B" train cable spread rooms within the Reactor Auxiliary Building. The breach was identified during maintenance activities to resolve a long-standing Thermo-Lag issue. Follow-up investigation revealed an additional Thermo-Lag fire barrier deficiency in a floor drain assembly in the cable spreading room. These breaches made it possible that a fire in the cable spreading room could adversely affect the "A" and "B" train safety-related cables. These conditions did not comply with the 3-hour fire-rated-barrier requirement contained in the Harris FSAR and were determined to constitute operation outside the design basis of the plant. The licensee will resolve the barrier breach via an on-going penetration upgrade effort prior to September 15, 1997. This LER will remain open pending the licensee's completion of the upgrade effort.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on May 15, 1997. The licensee acknowledged the findings presented.

Proprietary information was reviewed during the inspection but is not contained in this inspection report.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

D. Alexander, Supervisor, Licensing and Regulatory Programs
D. Batton, Superintendent, On-Line Scheduling
D. Braund, Superintendent, Security
B. Clark, General Manager, Harris Plant
A. Cockerill, Superintendent, I&C Electrical Systems
J. Collins, Manager, Training
J. Dobbs, Manager, Outage and Scheduling
J. Donahue, Director Site Operations, Harris Plant
R. Duncan, Superintendent, Mechanical Systems
W. Gautier, Manager, Maintenance
W. Gurganious, Superintendent, Environmental and Chemistry
M. Hamby, Supervisor, Regulatory Compliance
M. Hill, Manager, Nuclear Assessment
D. McCarthy, Superintendent, Outage Management
B. Meyer, Manager, Operations
K. Neuschaefer, Superintendent, Radiation Protection
W. Peavyhouse, Superintendent, Design Control
W. Robinson, Vice President, Harris Plant
G. Rolfson, Manager, Harris Engineering Support Services
D. Shockley, Supervisor, Configuration Manager
V. Stephenson, Manager, Rapid Response
T. Walt, Manager, Performance Evaluation and Regulatory Affairs

NRC

T. Le, Harris Project Manager, NRR
M. Shymlock, Chief, Reactor Projects Branch 4

INSPECTION PROCEDURES USED

IP 37550:	Engineering
IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 50002:	Steam Generators
IP 57080:	Nondestructive Ultrasonic Examination Observation
IP 60710:	Refueling Activities
IP 61726:	Surveillance Observation
IP 62700:	Maintenance Implementation
IP 62707:	Maintenance Observation
IP 64704:	Fire Protection Program
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 73753:	Inservice Inspection
IP 83750:	Occupational Radiation Exposure Controls
IP 90712:	In-Office Review of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92700:	Onsite Followup of Events
IP 92901:	Followup - Plant Operations
IP 92903:	Followup - Engineering
IP 93702:	Onsite Response to Events

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-400/97-04-01	VIO	Failure to comply with TS 3.0.4 prior to entry into Mode 6 from defueled condition (Section O1.3).
50-400/97-04-02	VIO	Three examples of failure to effectively implement corrective actions for previous non-conformances (Sections O4.1, O4.2, and O8.1).
50-400/97-04-03	NCV	Failure to establish and implement procedures for using appropriate test equipment on emergency battery during discharge test (Section M2.4).
50-400/97-04-04	EEI	Inadequate 10 CFR 50.59 safety evaluation for removal of containment equipment hatch missile shields while in Mode 3 (Section M3.1).
50-400/97-04-05	NCV	Failure to implement the design verification requirements of 10 CFR 50, Appendix B, Criterion III for safety-related configuration changes (Section E1.1).
50-400/97-04-06	NCV	Failure of workers to promptly leave a work area when their electronic dosimeters alarmed as required by procedure AP-535, Section 5.16.5 (Section R1.2).

50-400/97-04-07	NCV	Failure to tag and label radioactive material in accordance with procedure HPS-NGGC-0003, paragraph 9.2, Tagging and Labeling of Radioactive Material (Section R1.3).
50-400/97-04-08	VIO	Failure to provide functional testing for seismically qualified check valves in the fire protection system (Section F2.2).

Closed

50-400/96-02-03	URI	Use of potentially unconfirmed information obtained via telecons in engineering design work (Section E8.1).
50-400/97-007-00	LER	Inoperable component cooling water system - technical specification 3.0.3 entry (Section O8.1).
50-400/97-005-00	LER	Failure to perform core flux mapping following plant operation with reactor power greater than 100 percent (Section O8.2)

Discussed

50-400/96-04-04	URI	Tracking FSAR discrepancy resolution (Section E8.2).
50-400/97-006-00	LER	Breach in reactor auxiliary building 3-hour rated fire barrier (thermo-lag wall in cable spread room) (Section F8.1).