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:	January 5 - February 15, 1997
Inspectors:	J. Brady, Senior Resident Inspector D. Roberts, Resident Inspector R. Aiello, Reactor Engineer, DRS (paragraphs O1.2, O5.1, M2.1) C. Payne, Reactor Engineer, DRS (paragraph O5.1) M. Miller, Reactor Inspector, DRS (paragraph M1.1, M1.2) R. Hall, NRC 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 50-400/97-01

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 regional reactor engineers and a regional reactor inspector.

Operations

- In general, the conduct of operations was professional and safety-conscious (Section 01.1).

- Operator performance during several abnormal plant challenges was good, including a reactor trip (Section 01.3), subsequent unit restart (Section 01.4), and an unplanned boron dilution (Section 01.6). The post-trip crew debrief was excellent (Section 01.3), and the post-trip review package was thorough (Section 01.4). However, there was a late Notice of Unusual Event declaration and NRC notification related to a Security Alert event (Section 04.1 and Section P4).

- An unresolved item was identified pertaining to the unavailability of an immediate means for the Operations Shift Supervisor to check operator license conditions as required by plant procedures (Section 01.2).

- The Licensed Operator Requalification program continues to meet NRC requirements. In addition, the licensee was effective in determining the errors that had, or could have, occurred over the past year as well Additional emphasis on human performance error reduction techniques, particularly in the area of identifying each instance of the operators failing to comply with management standards and expectations, was needed as the common factors that contributed to most of the personnel errors. Shift management and supervisors were proactive in taking steps to mitigate the number of operator errors by standardizing communications protocol, ensuring operators continuously use procedures, and instituting a peer check policy (Section 05.1).

- A violation was identified when inadequate corrective actions for a Licensee Event Report (LER) resulted in an additional non-compliance with Technical Specification 3.2.3 Action Statement C.1, which required core flux mapping when power exceeded 100.0 percent power. The cause was the inappropriate use of a Technical Specification Basis change to accomplish a Technical Specification change (Section 08.3).

Maintenance

- Overall, maintenance and surveillance activities were performed well (Section M1). The licensee had addressed issues to improve maintenance for electrical equipment. The electrical areas examined were well maintained (Section M1.2).

- One violation was identified for a deficient engineering surveillance test procedure in which the end-of-life moderator temperature coefficient was calculated incorrectly for each of the last five core operating cycles (Section M2.2).

- The maintenance rule expert panel composition and knowledge was adequate. However, the panel was not always prompt in addressing maintenance rule responsibilities (Section M7.1).

Engineering

- Engineering support was good, particularly during the forced outage. System engineers were routinely involved in solving problems with plant equipment (Section E2).

- The violation identified in the maintenance area above for a deficient engineering surveillance procedure was the result of inattention to detail by the engineering staff in the procedure development and review process (Section E3.1).

Plant Support

- The general approach to the control of contamination and dose for the site was good (Section R1.1).

- Several emergency preparedness drills were conducted. The scenarios were challenging and offered licensee personnel a chance to train in a controlled environment. The licensee critiques were good and showed good self assessment capabilities. Management's decision to conduct these training drills and the decision to break intermittently for critiques was considered a strength (Section P1.1).

- Two examples of failure to follow emergency preparedness procedures were identified as a non-cited violation. These examples were associated with a late Notice of Unusual Event declaration and subsequent late NRC notification following a January 22, 1997 Security Alert (Section P4).

- Security and safeguards activities were performed well, particularly during the Security Alert event on January 22, 1997 (Section S1).

- Fire protection activities were generally acceptable (Section F1.1).

Report Details

Summary of Plant Status

Unit 1 began this inspection period at 100 percent power. On January 31, 1997, after the unit was reduced to 97 percent power in preparation for end-of-life (EOL) moderator temperature coefficient (MTC) testing and during quarterly testing on the main steam and feedwater isolation valves, the "A" steam generator feedwater isolation valve, 1FW-159, failed shut. Several operator attempts to reopen the valve were unsuccessful and the unit tripped on Low-Low "A" steam generator level. After repairs were completed for the valve and other plant equipment, the unit was restarted on February 1, 1997. The generator was synchronized to the grid on February 2 and the reactor returned to 100 percent power on February 3, 1997. Reactor power was reduced to 97 percent on February 6 to facilitate the EOL MTC testing. On February 7, 1997, the reactor was returned to 100 percent power where it remained for the remainder of the period.

I. Operations

01 Conduct of Operations

01.1 General Comments (71707,71714)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

01.2 Review of General Plant Operations

a. Inspection Scope (71707)

The inspectors conducted Main Control Room (MCR) tours and observations to verify that facility operations were being safely conducted within regulatory requirements. These tours included observation of instrument and recorder traces of safety-related and important-to-safety systems for abnormalities, control board walkdowns, MCR access controls and operator behavior, and reviewing operator logs and shift turnover sheets.

b. Observations and Findings

The inspectors noted that shift superintendents have no immediate means to verify licensed operator license conditions or individual requalification status. OMM-001, "Conduct of Operations", Revision 18, states in part, that the Superintendent, Shift Operations (SSO), is responsible for assuring that scheduling provides proper staffing for each shift for normal operational activities and postulated emergency situations. OMM-001 also states that shift staffing schedules must include TS 6.2.2 compliance and the principles of good operating practice.

The licensee discussed with the inspector a tracking program for personnel qualification that will provide this capability. The inspector reviewed the meeting minutes from a July 19, 1996 meeting of the training advisory board. Action items 96-16, 96-17, and 96-18 address the problem discussed above from a site wide training and qualification status. The new personnel qualification tracking system was not yet available at the time of this inspection. This issue is unresolved pending inspector review of whether the abscence of an immediate licensee condition verification method has resulted in unqualified operations personnel standing on-shift duty and will be tracked as Unresolved Item 50-400/97-01-01, Tracking Operator License Conditions in the MCR.

c. Conclusions

One unresolved item was identified for the lack of having an immediate means for shift superintendents in the main control room to verify the requalification status or other license conditions for shift operators.

01.3 Reactor Trip

a. Inspection Scope (93702)

The inspectors observed the response to a reactor trip that occurred on January 31, 1997 to determine if procedures were followed and if plant equipment performed as designed.

b. Observations and Findings

The reactor was at 97 percent power in preparation for performing the end-of-life moderator temperature coefficient test. The operators were performing OST-1018, Main Steam Isolation Valve and Main Feedwater Isolation Valve Operability Test, Revision 7, on the feedwater isolation valve for the "A" steam generator (1FW-159). This involved a ten percent movement of the valve disk from full open to verify freedom of motion. Valve 1FW-159 unexpectedly went full shut which resulted in a mismatch between feed flow and steam flow for the "A" steam generator. The board operator attempted unsuccessfully to open the valve several times. The senior control operator attempted to run back turbine power at ten megawatts per minute to match steam flow with feed flow. The operators also opened the feedwater regulating valve fully to maximize feed flow through the preheater bypass line. Although this action cleared the mismatch bistable, steam generator level shrank due to both the mismatch and power reduction such that a reactor trip occurred due to Low-Low steam generator level in the "A" steam generator. The turbine tripped as required. An automatic start of the auxiliary feedwater (AFW) pumps occurred as required.

The refilling of the steam generators with AFW flow cooled the reactor coolant system such that pressurizer level shrank to 17 percent resulting in pressurizer heaters tripping and letdown isolating. The inspector concluded that the letdown isolation could have been avoided.

The licensee determined that condenser steam dump operation was sluggish and may have contributed to the greater than expected cooldown which resulted in the letdown isolation (CR-97-00549). When pressurizer level was restored, pressurizer heaters were turned back on. Later in the recovery the operators found the group "A" heaters had tripped.

The inspector attended the post-trip operating crew debrief which was attended by the Plant General Manager, other members of licensee management, and maintenance personnel that were assigned troubleshooting responsibility. Written statements prepared by the involved operators described the evolutions that led to the trip and indications that were received during the response to the trip. The brief was well organized and thorough. The pre-trip feedwater isolation valve actions were reviewed in detail. The operators discussed the pressurizer heater group "A" trip. They also thought that the level indicated on the "A" steam generator water level gage on the Main Control Board was at 44 percent when the reactor trip occurred instead of the 38.5 percent reactor trip setpoint. Plant computer data was printed which showed that level was at 38.5 percent. The feedwater isolation valve problem, pressurizer heater group "A" trip, and steam generator water level setpoint issue were included in the post-trip review package (discussed in Section 01.4) as items to resolve prior to startup.

c. Conclusions

Operator response to the reactor trip was acceptable. Plant safety equipment responded as expected to the reactor trip. The post-trip crew debrief was excellent.

01.4 Post-trip Review

a. Inspection Scope (93702)

The inspectors reviewed the licensee's post-trip review procedure for the January 31, 1997 reactor trip to determine whether all related problems and corrective actions had been documented. The inspectors independently reviewed post-trip data to evaluate operator and plant performance. The inspector attended the Plant Nuclear Safety Committee meeting for which the post-trip review package and unit restart were agenda items.

b. Observations and Findings

Procedure OMM-004, Post trip/Safeguards Actuation Review, Revision 4, describes the licensee's post-trip review process. The post-trip review package required by OMM-004 was approved by the Plant Nuclear Safety Committee on February 1, 1997. Based on correction of the root cause of the trip, and resolution of other trip-related deficiencies, reactor restart approval was documented on an OMM-004 attachment and granted on February 1.

The root cause of the trip was the failure of a solenoid-operated valve in the hydraulic actuator for the "A" Steam Generator (SG) feedwater isolation valve, 1FW-159. The valve failed shut during surveillance testing, and attempts to reopen it were unsuccessful, resulting in the reactor tripping on Low-Low level in SG "A". The defective solenoid was replaced and the valve was returned to service prior to restarting the Unit on February 1, 1997.

Other problems encountered during the reactor trip and discussed in the OMM-004 package included a small body-to-bonnet leak on pressurizer spray valve 1RC-103, an apparent discrepancy between the indicated SG water level and the SG level setpoint at which the reactor tripped, and a breaker failure associated with the "A" group of pressurizer backup heaters. These problems and related troubleshooting and repair activities were discussed thoroughly in the post-trip package.

Although the licensee was unable to stop or reduce the leak on the pressurizer spray valve, the RCS unidentified leakage values remained within TS limits and the licensee set up continuous camera monitoring capability which operators observe during routine rounds. Operations management instructed operators via a Night Order to notify management and perform more frequent leakrate determinations if the unidentified leakage value increased by 0.2 gpm over the previous data.

During the plant transient, the pressurizer backup heaters had deenergized as required when pressurizer level dropped to 17 percent due to the shrink following the trip. The heaters were reenergized by control room operators a short time after pressurizer level was restored. Moments after energizing the heaters, the reactor operator noticed that the "A" group of heaters was off although its control switch was in the "on" position. This group was observed to be energized earlier suggesting that its breaker had tripped. The licensee was unable to determine the root cause of the pressurizer backup heater breaker failure during several troubleshooting efforts. However, a malfunctioning test switch was replaced and the breaker was cycled several times without further incident.

Just moments before the reactor trip, control room operators had observed SG water level to be decreasing very slowly and indicating approximately 44 percent on the control board narrow range indicators. The SG Low-Low level reactor trip setpoint is approximately 38.5 percent of narrow range instrument span. Before operators could complete actions to restore water level or reduce turbine load after the feedwater valve closure, the reactor tripped. The operators thought that the "A" SG water level was still near 44 percent when the reactor tripped and identified this as a potential discrepancy between control panel indications and the reactor trip setpoints. Troubleshooting of the SG level instrument loops indicated that the instruments all tracked consistently with their respective channels for slow and fast manipulations. No significant realignments were required. The licensee was unable to draw a firm conclusion but suggested in the OMM-004 package that the perceived discrepancy was due to a possible combination

of operator distraction and a SG water level shrink due to the operators' initial attempt to reduce power.

The OMM-004 package included an evaluation of chart recorder data for pressurizer and steam generator levels, pressurizer pressure, and average RCS temperature. According to the data, the "A" SG water level went off-scale low for a very short time before being restored by the auxiliary feedwater system. The minimum RCS average temperature during the transient was 541 degrees Fahrenheit. Data from the plant computer's sequence of events log was consistent with the data on the chart recorders, and with the various narratives contained throughout the post-trip package. The licensee's comparison of the plant's response with the corresponding event in the FSAR accounted for minor differences between the actual event and the total loss of feedwater analyzed in the FSAR. The licensee's evaluation concluded that the plant's response was consistent with the FSAR. Three ancillary discrepancies between the plant and the FSAR dealing with normal operating water volume in the pressurizer, the low feedwater flow reactor trip setpoint, and periodic testing of the feedwater isolation valves were documented in CR 97-00443 for long-term resolution.

c. Conclusions

The inspectors concluded that the OMM-004 post-trip package was thorough. The inspector's independent review of post-trip data concluded that plant performance was as expected. The root cause of the trip was corrected prior to restarting the unit. Several trip-related issues were resolved prior to restart, and plans for long-term corrective and/or compensatory actions were completely documented. Additionally, the inspector considered the related PNSC meeting to be adequate.

01.5 Startup Activities

a. Inspection Scope (71707)

The inspectors observed the reactor startup on February 1, 1997, and generator synchronization to the grid on February 2, 1997 following the January 31 reactor trip.

b. Observations and Findings

The inspectors observed that operators were following procedures and ensuring that plant equipment performed as expected. Reactor engineers were present and provided assistance to operators for the required reactivity plots. Reactor criticality was achieved within the allowable tolerance band of the estimated criticality conditions (expected control rod "D" Bank position and RCS boron concentration).

c. Conclusions

Operator and reactor engineering performance during this startup was good.

01.6 Boron Dilution Event

a. Inspection Scope (71707)

The inspectors observed the response to a boron dilution event that occurred on February 9, 1997 to determine if procedures were followed.

b. Observations and Findings

The inspector observed that the operators were prepared and anticipated potential problems that might occur during the fill and vent of the Boron Thermal Regeneration System (BTRS). The system is used for end-of-cycle reactivity control. The system replaces the use of the normal dilution method to change Reactor Coolant System boron concentration. The operation was being performed using procedure OP-108, Boron Thermal Regeneration System, Revision 7, Section 8.9. Prior to starting the evolution, operators discussed the potential for leakage of unborated water into the letdown system. The volume control tank (VCT) level was being trended on the Main Control Board plant computer screen. The procedure provided for aligning the system such that unborated reactor makeup water could fill and pressurize the system to greater than 100 psig. That operation was commenced at 3:52 p.m. on February 9, 1997.

At approximately 4:05 p.m. the control room operators identified an upward trend in VCT level. The pressurization evolution could not be immediately secured because the system fill valve was located in a locked high radiation area and the auxiliary operator had exited that area to check other portions of the system for leaks. There were two potential sources of VCT inleakage from the pressurized BTRS. The operators were not sure which source was the problem. After consulting a flow diagram, operators shut an automatic BTRS-to-VCT inlet isolation valve (1CS-570) from the main control room at 4:19 p.m. Shutting valve 1CS-570 isolated the already shut manual isolation valve 1CS-577 from the VCT and the tank level stabilized. Operators concluded that valve 1CS-577 was leaking by. The procedure was stopped and a work request written to repair the valve.

The inspector reviewed the Emergency Action Level flow path contained in Plant Emergency Procedure (PEP) 110, Emergency Classification and Protective Action Recommendations, Revision 1. One item in the flow path pertained to an "Uncontrollable Boron Dilution". If the uncontrollable boron dilution was answered yes, the criteria for declaring an "Alert" was a dilution event lasting greater than 15 minutes. The inspector observed that this event lasted approximately 24 minutes. The inspector discussed with the licensee the basis for their decision not to declare an Alert. The licensee believed that since the system is only used at end-of-life and had been out of service for an

extended period of time, that the possibility of leakage was anticipated. Considering this was a planned evolution, it was concluded not to be an uncontrollable boron dilution.

Because this event occurred so late in core life, the effect of the two-inch VCT level increase (approximately 50 gallons of pure water added to the RCS) had no detectable affect on RCS temperature or on reactor power. The licensee included a corrective action in Condition Report 97-00703 to revise the EAL flow path to provide a better definition for an uncontrollable boron dilution.

c. Conclusions

The inspector concluded that the operator response to this event was prompt and appropriate and that it was properly classified.

02 Operational Status of Facilities and Equipment

02.1 Engineered Safety Feature System Walkdowns (71707)

a. Inspection Scope (71707)

The inspectors used Inspection Procedure 71707 to walk down accessible portions of the emergency service water system (FSAR Section 9.5.8). The inspectors used the current valve lineup checklist from operating procedure, OP-139, Service Water Systems, Revision 12, and simplified flow diagrams, CPL-2165-S-0547, CPL-2165-S-0548, CPL-2165-S-633, CPL-2165-S-808, CPL-2165-S-998, and CPL-2165-S-999 to verify the correct valve and instrument lineup at the site.

b. Observations and Findings

The emergency service water system piping runs from the emergency service water structures to the Reactor Auxiliary Building, Turbine Building, Diesel Generator Building, and Containment Building. The following minor inconsistencies were found during the inspection:

- There were a total of twenty-three valves that were locked in the field and marked locked on the lineup checklist, but were not shown as locked on the simplified flow diagram. There were two valves marked capped on the flow diagrams, but were not marked as such on the lineup checklist. There were two valves that were shown as open on the simplified flow diagram, but were capped and shut in the field and on the checklist. There were three valves marked capped on the valve lineup checklist, but were not capped in the field or on the flow diagram. These examples were inconsistent with the licensee's general practice of designating locked or capped valves as such on both the flow diagrams and the lineup checklists.

- There were two valves that had no identification tags.

- The emergency service water discharge strainer 1B-SB motor breaker was found energized with the control switch positioned away from the ON position near the tripped position (45°). A licensee operator repositioned the switch to the on position and no abnormalities were noticed. The licensee determined that the switch had not been in the tripped position, and the motor breaker was operable.

The above discrepancies were presented to the licensee. The licensee was evaluating the items and determining the appropriate corrective action.

c. Conclusions

Equipment operability, material condition, and housekeeping were generally acceptable.

04 Operator Knowledge and Performance

04.1 General Comments

The inspectors observed and evaluated operator performance during several unusual or infrequent occurrences throughout the inspection period. These included the January 22, 1997 Security Alert, the January 31 reactor trip, the February 1 plant startup, and the February 9 boron dilution event (all discussed throughout this inspection report). Two of these activities required operator entry into the Emergency Action Level flow path and two required NRC notification. The only event that contained negative findings was the Security Alert. As mentioned throughout the report, operator performance during the boron dilution event and the plant transients was good.

Management attention to error reduction has been extensive during the past six months including the use of consultants, a human performance specialist, and focus groups. Management recognized the slight increase in errors during the summer of 1996. Errors have been tracked and categorized in great detail in order to determine if common themes existed. The tracking included not only the errors committed but near-misses as well. In addition, critiques of the error or near-miss were being conducted within each shift and between shifts. The inspector observed that the threshold for classification as an error was very low making the number of errors in the tracking matrix higher than their corresponding collective safety significance. Some of the corrective actions taken are described in section 05.1. In addition, personnel actions have been taken in some situations. The inspectors have observed that operator attitudes toward safety in the past have been good and that no change in that attitude has been observed.

05 Operator Training and Qualification

05.1 Licensed Operator Requalification Training

a. Inspection Scope (71001)

The inspectors reviewed the licensee's requalification program for licensed reactor operators and senior reactor operators. The inspectors reviewed the common cause analysis for the operator errors that were made in 1996 and reviewed licensee activities conducted during the inspection to mitigate these recent events. The inspectors also interviewed selected licensed operators and members of the training staff. The inspectors reviewed several Condition Reports (CRs) relating to the operator errors that occurred in 1996 in an attempt to identify those areas needing improvement. The inspectors then compared these areas with training plans and with licensee management expectations.

b. Observations and Findings

The inspectors observed licensed operator requalification (LOR) simulator training of eight Shift B operators and nine staff operators split into three separate crews. This week of training included normal shutdown and startup of the facility, as well as an evaluated scenario for each crew covering emergency operations. The inspectors noted that the evaluation and training scenarios were well developed and exercised the operators on a wide variety of normal, abnormal and emergency conditions. The inspectors also observed that the post-scenario critiques by the training staff were generally accurate and identified significant performance deficiencies. Some instances of poor communication practices were noted by the inspectors but not identified in the critique.

During 1996 after each LOR simulator session was completed, the Superintendent of Operations Training transmitted a training assessment to the Operations Manager. This assessment included a summary of training topics covered during the session, operator and crew performance, and an analysis of this performance against five key performance parameters (communications, adherence/use of procedures and references, control board operations/diagnostics, self verification Stop Think Act Review (STAR), and teamwork/command and control). The inspectors reviewed these assessments for objectivity, thoroughness, and trending of operator performance. The inspectors noted that the assessments were the compilation of approximately 70 operator and 13 crew evaluations and thus were not quantitative in their ability to trend long term performance. The inspectors also noted that the assessment contained an extensive listing of specific performance weaknesses or areas needing improvement that were observed by the training staff during the session. Based on qualitative evaluation, training management determined whether performance was below, met, or exceeded expectations; and the trend of that performance (improving, stable or declining).

The inspectors determined that the assessments were thorough summaries, though subjective, of operator performance during the simulator training sessions. However, the inspectors also determined that many of the same type of operator performance errors and weaknesses continue to recur. Based on the training and evaluation scenarios observed during the inspection week, the inspectors noted that many of the errors highlighted in the 1996 simulator training assessments continue to be observed in 1997. For example, some operators continue to speak in low voices that preclude the sharing of information with all crew members. Slang was observed to still be in use by the operators. Operators still made errors in the transition between two-way and three-way communication. Operators also did not always close communication loops and crew briefings were poorly timed, were not performed, or lacked meaningful information.

The inspectors found that recommendations of INPO Significant Operating Experience Report (SOER) 92-1, "Reducing the Occurrence of Plant Events Through Improved Human Performance" had been adopted by the licensee. Despite these actions, some operator errors continue.

The licensee used error reduction methods developed by a contractor. The inspectors observed two training sessions where a licensee evaluator trained in error reduction techniques participated in critiquing the operator's performance. The evaluator's comments were specific, detailed and addressed various operator performance errors.

The inspectors also noted that senior plant management had concluded that a large number of operator performance errors over the last year were associated with non-licensed operator (NLO) activities that were performed by licensed operators. As a result, consideration was being given to modifying the LOR curriculum to incorporate more NLO-type training into the two-year program. The inspectors interviewed the training staff and found that this review had a goal date of March 31, 1997. The instructor was asked the type of tasks being considered for inclusion in the LOR program. The instructor indicated that important, safety-related tasks were the primary focus for inclusion. The inspectors pointed out that many of the performance errors that occurred over the past year were generally routine, non-safety-related tasks. The inspectors concluded that the benefit of adding NLO training to the curriculum could be diminished if this data was not also considered in the review.

c. Conclusions

The inspectors concluded that the licensee's LOR program continued to meet the NRC requirements of 10 CFR 55.59. Licensed operator and instructor performance was satisfactory. The training and evaluation simulator scenarios were comprehensive and challenged the knowledge, skills and abilities of the operators. The training staff was effective at finding weaknesses in the operator's technical skills; however, additional emphasis on human performance error reduction techniques, particularly in the area of identifying each instance of the operators

failing to comply with management standards and expectations, was needed.

The inspectors determined that the licensee was effective in determining the errors that had, or could have, occurred over the past year as well as the common factors that contributed to most of the personnel errors. The inspectors concluded that implementation of the usual techniques common throughout the industry for combatting human errors (such as STAR, procedural usage, and three-way communications) were currently not having the desired effect of reducing the number of operator performance errors that have occurred at Harris. Consequently, other innovative techniques may be needed to improve future performance. The inspectors noted that shift management and supervisors were proactive in taking steps to mitigate the number of operator errors by standardizing communications protocol, ensuring operators continuously use procedures, and instituting a peer check policy. Operator attitudes were focussed on safety.

07 Quality Assurance in Operations

07.1 Licensee Self-Assessment Activities (40500)

a. General Comments

During the inspection period, the inspectors reviewed multiple licensee self-assessment activities, including:

- a February 1, 1997 Plant Nuclear Safety Committee (PNSC) meeting;
- Nuclear Assessment Section Audit on Fire Protection (HNAS 97-011);

Licensee performance for these activities was adequate.

08 Miscellaneous Operations Issues (92700, 92901)

08.1 (Closed) LER 50-400/96-006-00, Main Feedwater Isolation Valve 1FW-277 Valve Stem to Disc Failure.

This event was reported because of the discovery that the "B" Steam Generator Main Feedwater Isolation Valve (1FW-277) stem and disc had separated. The problems with the valve were identified on March 22, 1996 when the valve was stroked with the unit shutdown. The issue was addressed in NRC IR 50-400/96-04. Inspectors observed the disassembled valve, failed stem, attended Plant Nuclear Safety Committee (PNSC) meetings related to the investigation, and reviewed the cause of the valve failure at that time. Conclusions from that review were documented in IR 50-400/96-04.

A Metal Impact Monitoring System alarm for the "B" Steam Generator concurrent with a momentary low nitrogen pressure alarm on 1FW-277 occurred on February 15, 1996. On March 4, 1996 the valve was partially stroked per surveillance procedure OST-1018, Main Steam Isolation and Main Feedwater Isolation Valves Operability Test Quarterly Interval Mode

1, Revision 7. On March 15, 1996 a flow reduction trend was noted on the Main Feedwater preheater line flow data. Troubleshooting identified that the problem was associated with either a feedwater line check valve or 1FW-277. The unit was shutdown on March 22, 1996 due to an unrelated missed surveillance on the diesel generator load sequencer. The valve was immediately tested and the stem disc separation was confirmed. The cause of the separation was due to a manufacturing defect that caused the gate to contact the bonnet causing low cycle fatigue. The stem was replaced; the new stem machined to fit the gate; the valve was reassembled and properly tested. Corrective Maintenance Procedure CM-M0204, Main Feedwater Isolation Valve, was revised to add steps to check the gate to dome area inside bonnet during reassembly. The inspector verified that CM-M0204, Revision 6, had these steps.

The licensee concluded that the valve was unable to perform it's containment isolation function and that Technical Specification 3.6.3 action statement to isolate the affected penetration in 4 hours or be in Cold Shutdown in the following 36 hours was violated. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the Enforcement Policy (NCV 50-400/97-01-02).

08.2 (Closed) VIO 50-400/96-04-02, Inadequate Corrective Action for Resin Spill and Reactor Switchgear Voltmeter Deficiency.

This violation was issued because two examples of inadequate corrective action were identified. The immediate corrective actions taken were reviewed and discussed in Inspection Report 50-400/96-04. The licensee's response of June 18, 1996 discussed the corrective actions for both examples.

The first example involved resin from the waste processing demineralizer skid that had been blown into the floor drain system during the resin replacement venting process. This resin had come out of some of the floor drains and had caused two personnel contaminations. The event had also occurred in 1995. The licensee removed the resin tank vent hose from the floor drain connection and reconnected it to the spent resin header. Procedure changes were made to OP-120.09, Radwaste Demineralizer Skid, Revision 8, that incorporated direction not to connect the vent valve header to the floor drains. The inspector field verified that the change had occurred. In addition, the inspector discussed the change with operations personnel. The inspector also reviewed a training brief that was distributed to site management personnel on August 26, 1996 that addressed corrective action program implementation.

One additional event involving contamination coming out the same floor drains had occurred since then and was documented on condition report 97-00087. The inspector discussed the additional event with operations personnel and concluded it was not related to operation of the demineralizer skid. The additional event related to a design deficiency that did not allow the equipment drain portion of the floor drain system

to properly vent forcing it to vent through the floor drains. This example was being adequately resolved.

The second violation example involved the use of the "B" train P4 contact verification switch for surveillance testing when the switch had a documented deficiency. The inspector verified that PLP-103 Surveillance and Periodic Test Program, Revision 10, included guidance that all deficiencies on test instruments are to be evaluated for their affect on the test prior to beginning the test. The inspector reviewed a memorandum that was sent to site personnel by the Director of Site Operations relating to the P4 switch incident which communicated the expectations that were inserted in PLP-103.

The inspector concluded that the violation examples were adequately corrected. This item is closed.

08.3 (Closed) LER 50-400/96-003-00, Failure to Perform Core Flux Mapping Following Short Power Excursions Over 100 percent.

This LER was issued to report a failure to perform flux mapping as required by Technical Specification (TS) 3.2.3 action C.1 when the prohibited region of operation shown on TS Figure 3.2-3 was entered. Figure 3.2-3 was added in amendment 50 when TS 3.2.3 was changed to be less restrictive. The figure has flow rate on the vertical axis and power Percent of Rated Thermal Power (%RTP) on the horizontal axis. A line at 100.0 percent power separates the region of permissible operation from the region of prohibited operation. The licensee identified 19 occasions in the past when power had exceeded 100.0 percent for short durations and flux mapping had not been performed as required by the TS.

The licensee's corrective actions included a change to the TS bases to clarify when core flux mapping is actually required, a TS interpretation to clarify how rated thermal power calculations were to be rounded, and a procedure change to strengthen review and implementation of TS changes. The inspector reviewed TS Interpretation 96-01, Rounding Rule for TS LCO 3.2.3 which invoked American Society for Testing and Measurement Standard E29, Revision A (1993), Standard Practice for Using Significant Digits in Test Data to Determine Conformance to Specifications. The TS Interpretation uses standard roundup techniques. Thus 100.05 percent rated thermal power would be rounded down to 100.0 percent and 100.06 percent rated thermal power would be rounded up to 100.1 percent. The inspector found this consistent with standard engineering practice.

10 CFR 50.36 states that the technical specifications will be derived from the analyses and evaluation include in the safety analysis report and amendments. It also states that a summary statement of the bases or reasons for such specifications, other than those covering administrative controls, shall also be included in the application, but shall not become part of the technical specifications. The inspector reviewed the change to the basis for TS 3.2.3. The change incorporated

NRC guidance to inspectors for enforcement of rated thermal power contained in NRC Inspection Procedure 61706. This guidance was not issued for the purpose of defining rated thermal power for licensees. Rated thermal power is already defined for licensees in their operating license and the Technical Specification Definition section. The Operating License (NPF-63) and Technical Specifications for docket 50-400 state that rated thermal power is 2775 megawatts thermal (100 percent rated core power). The new basis used the enforcement guidance to inspectors for the purpose of redefining 100.0 percent rated thermal power as a number that floats based on the amount of time that power was over rated thermal power. As such, power could be as high as 102 percent, without the licensee declaring that rated thermal power had been exceeded and a flux map initiated. The inspector considered that the basis statement and the Technical Specification were in conflict.

The inspector reviewed the February 21, 1996 Plant Nuclear Safety Committee (PNSC) meeting minutes associated with the LER. The minutes included a discussion of the problems created with TS 3.2.3 due to ammendment 50 and that the preparation and review of ammendment 50 was considered inadequate. The minutes also indicated that the words which were included in the new TS Basis for TS 3.2.3 were discussed and agreed to although there was no mention that they would be put in the TS Basis. The inspector observed that the minutes did not mention any discussion about processing a TS change. The inspector considered that the PNSC missed an opportunity to ensure that this problem was properly corrected.

The inspector reviewed licensee calorimetric data from operator logs for the performance of procedure OST-1004, Power Range Heat Balance, Computer Calculation. In addition, the inspector discussed the LER and bases change with operators. The inspector became aware of a performance of OST-1004 on March 20, 1996 when the calorimetric value of power was 100.2 percent. The inspector reviewed the operator logs for that performance and the OST-1004 data sheet that documented the calorimetric, then interviewed the shift personnel involved with that performance and the shift supervisors for the next two shifts (24 hrs). The inspector concluded from these reviews that the event reported in the LER had recurred on March 20, 1996 in that power had exceeded 100.0 percent (100.2 percent) and a flux map was not performed. The interviews indicated that the operators had chosen to use the new TS Basis as the foundation for their decision. The licensee's decision was based on considerable discussion over several shifts.

The inspector discussed this issue with licensee management on January 29, 1997. The licensee generated a TS Basis change to remove the conflicting verbage, which was sent to the NRC on February 13, 1997.

Regulatory Significance

10 CFR 50, Appendix B, Criterion XVI requires that measures be established to assure that conditions adverse to quality such as deficiencies, deviations, and nonconformances are promptly identified

and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The licensee identified violations of Technical Specification 3.2.3 and reported them under 10 CFR 50.73 in LER 50-400/96-003-00. However, the corrective actions described in the LER, when implemented, contributed to the violation recurring on March 20, 1996. This is considered a violation of 10 CFR 50, Appendix B, Criterion XVI, inadequate corrective action pertaining to LER 96-003-00 for core flux mapping (50-400/97-01-03). Licensee corrective actions will be reviewed during the closure of the violation. This LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

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

- WR-ACWH 003, 5232 125VDC Distribution System, Perform C&D Battery Charger S/D Card Calibration.
- PIC-E049, C&D Battery Charger HV/UV Relay Card Calibration.

b. Observations and Findings

The inspector found the work performed under these activities was professional and thorough. All of the work observed was performed with the work package present and in use.

c. Conclusions

The inspector identified no deficiencies.

M1.2 Electrical Maintenance

a. Inspection Scope (62700)

The scope of the inspection was to review documentation and inspect the reactor trip breakers, high voltage transformers, high voltage switchyard, isolated phase bus, and 6.9kV breakers to determine if these items were adequately maintained and tested to assure operability. Walkdown inspections of the above electrical areas were conducted to determine the material condition of the equipment.

The inspector reviewed Final Safety Analysis Report (FSAR) Chapter 7, Section 7.2, Reactor Trip System and Chapter 8, Section 8.2, Offsite Power Systems, and Section 8.3, Onsite Power Systems to determine design requirements. The Technical Specification (TS) Section 3/4.3.1, Reactor

Trip System Instrumentation and 3/4.8, Electrical Power Systems were reviewed to determine testing and surveillance requirements.

b. Observations and Findings

The licensee conducted a self assessment for the Reactor Trip System - Safety System Functional Evaluation between November 18, 1996 and December 20, 1996. This self assessment included a review of maintenance procedures, corrective and preventive maintenance (PM) activities, testing, and surveillances for the Reactor Trip Breakers (RTB), the Reactor Trip Bypass Breakers, the Manual Reactor Trip Switches, and the Solid State Protection System. The self assessment was thorough and several minor concerns and weaknesses were identified with documentation for the trip breakers. The licensee initiated four Condition Reports (CR) to investigate, address, and correct any problems identified. The inspector reviewed and verified that the latest PMs and surveillances were performed as required. There was one open work order, WR/JO 96-AHPK1, for correcting the "B" RTB closing motor charging spring. The work was tentatively scheduled for February 3, 1997. There was no safety concern since the safety function of the RTBs is to trip open. The inspector concluded the RTBs are maintained in an adequate manner.

The inspector reviewed the Maintenance Items List for the 6.9kV breakers. Corrective maintenance adjustments were completed for breakers 101, 108, 122, 127, and 128. Work orders have been written to have breakers 101, 107, 122, and 127 overhauled during the upcoming refueling outage (RF07). Maintenance procedures PM-E0005 and PM-E0006 had been revised to clarify the Close Coil Gap Adjustment. New corrective maintenance procedure CM-E0026, 6.9kV Breaker Ratchet Wheel and 4 Bar Linkage Overhaul, was completed and issued. The inspector concluded the licensee has or was in the process of addressing and correcting the problems with the 6.9kV breakers in a satisfactory manner.

The inspector verified by reviewing the completed work orders that the required PMs were performed for the high voltage transformers, switchyard breakers, and disconnect switches. The maintenance activities in this area are performed by the off-site Transmission Group and monitored by an on-site system engineer. The on-site system engineer was very knowledgeable and cognizant of maintenance for the high voltage transformers and switchyard. The Transmission Group revised the 33 maintenance and PM procedures to enhance them. However, the inspector still considered that the procedures were brief, but adequate. In addition, the inspector concluded all the required maintenance and PMs including predictive maintenance, and oil analysis, are included in the Transmission Group's Maintenance Program for the Harris Site. The inspector concluded that maintenance activities for the high voltage transformers and switchyard were adequate.

The inspector verified that the isolated phase bus had been adequately maintained by the on-site Maintenance Department. The latest completed

PMs were reviewed and verified. However, procedure, PM-E0042, Main Generator Links Disconnection and Isolated Phase/Nonsegregated Bus Duct Inspection, does not specify the use of Doble testing to identify faults. The off-site Transmission Group specifies Doble testing for the high voltage transformers and switchyard. Certain types of faults can only be identified by Doble testing. The licensee indicated this concern would be addressed. The inspector concluded that the isolated phase bus was adequately maintained and that Doble testing would enhance the PM program.

During the walkdown inspections, the inspector observed that the plant was well maintained and no deficiencies were identified.

c. Conclusion

The inspector concluded that the licensee had addressed issues to improve maintenance. The electrical areas examined were well maintained. System engineers were knowledgeable of electrical maintenance requirements and addressed maintenance concerns in a timely manner.

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:

- MST-M0011, Emergency Diesel Generator Crankshaft Web Deflection and Thrust Clearance Check, Revision 6.
- MST-I0501, Diesel Generator 1A-SA Lube Oil and Jacket Water Heater Thermostat Calibration, Revision 5.
- MST-I0011, MSL Pressure, Loop 2 (P-0485) Channel Calibration, Revision 3.
- MST-I0122, P-0455 Operating Test, Revision 4.
- EPT-033, Emergency Safeguards Sequence System Test, Revision 16.
- OST-1021, Daily Surveillance Requirements Daily Interval, Modes 1,2, Revision 16.
- OST-1214, Emergency Service Water System Operability Train A Quarterly Interval, Revision 11.

b. Observations and Findings

While conducting the pre-run bar before the 8-hour diesel generator operation prerequisite for MST-M0011, Emergency Diesel Generator Crankshaft Web Deflection and Thrust Clearance Check, Revision 6, the licensee noticed that there was an unusual amount of air venting off in the engine control panel when the Maintenance Mode Selector Switch was taken to the maintenance mode. The licensee determined that the P-1 three-way-valve had developed a severe leak. The "A" EDG was declared inoperable until the licensee could determine if the faulted P-1 valve was required to be functional during normal or emergency operations. The inspector identified that the shift Senior Control Operator (SCO) attempted to continue with the "A" EDG barring procedure, SPP-0025, Emergency Diesel Generator Barring Procedure, Revision 2, in the face of this uncertainty. The auxiliary operator convinced the SCO that the barring procedure should be suspended pending management review. The licensee determined that the faulted P-1 valve did not render the EDG inoperable. The valve was later replaced. The inspector reviewed drawing 1364-16451, Revision 12, Diesel Engine Control Panel, and verified the licensee's conclusion.

c. Conclusions

The inspectors concluded that the licensee's actions to suspend the barring procedure pending further evaluation were appropriate. Workmanship during these activities was professional and thorough. All of the surveillances observed were performed with the procedure present and in use. No violations or deviations were identified.

M2.2 End-of-Life Moderator Temperature Coefficient Determination

a. Inspection Scope (61726)

The inspectors observed licensee performance of engineering surveillance test procedure EST-702, Revisions 10 and 11, Moderator Temperature Coefficient - End-of-Life Using the Boron Method, to verify that the end-of-life (EOL) moderator temperature coefficient (MTC) for the current fuel operating cycle (cycle 7) was within Technical Specification (TS) limits. The inspectors reviewed the test procedure in advance, and observed licensee performance during the test to verify compliance. This procedure implemented the surveillance requirement in TS 4.1.1.3.b which required that the MTC be calculated and compared to acceptance criteria within seven effective full power days of reaching an RCS boron concentration of 300 parts per million.

b. Observations and Findings

This test was controlled by reactor engineers who collected the data and calculated the MTC values. Main control room operators performed the required plant manipulations, and chemistry technicians obtained and analyzed the necessary RCS and pressurizer (PZR) boron samples at predetermined test hold points. The general test method was to

establish pre-test steady state conditions near full reactor power (approximately 97 percent of rated thermal power) and record initial plant data (RCS and PZR boron concentrations, average RCS temperature, and reactor power). The actual test was then conducted in two parts. During the first iteration, operators borated the RCS to create a slight drop in average RCS temperature while holding reactor power constant. The above test data was again collected at this intermediate point. In the second part, operators performed a boron dilution to return RCS temperature as close as possible to the initial value, again while holding reactor power at 97 percent. A final set of test data was recorded by the reactor engineers. An MTC value was calculated for each of the two transient end-states by performing an overall core reactivity balance which factored in changes due to boron and xenon concentrations, fuel temperature (Doppler effect), and fuel depletion. The MTC value to be compared with the TS limit was the average of the two end-state values.

The inspector attended the pre-job briefing for this activity which was conducted by the lead reactor engineer. The inspector observed portions of the sampling activities conducted by the chemistry technicians. These activities were conducted well. Control room operators successfully performed the required boration and dilution activities with minimal impact on the plant. As expected, power range nuclear instrumentation provided a non-conservative indication of reactor power while at the reduced RCS temperature, but the instruments' indications remained within two percent of the actual reactor power (based on heat balance calculations) as required by the TS.

Before the test was commenced, the inspector discovered an error in Revision 10, Attachment 6 which was used to calculate the MTC in the second part of the procedure. This error involved the contribution of the burnable poison xenon to the overall core reactivity balance. Specifically, procedure Attachment 6, steps 20 through 23, incorrectly calculated the sign (+ or -) of the change in reactivity due to xenon. Instead of subtracting the beginning state xenon reactivity value from the end state (as had been done for the first reactivity balance calculated in Attachment 4), the steps incorrectly subtracted the end state reactivity due to xenon from the beginning state value. Depending on the direction of the xenon transient at the time the data was collected, the error could have resulted in a non-conservative calculation of the final (average) MTC value. The inspector informed the appropriate plant personnel of the error just prior to the test being commenced.

A day later, after data collection and calculations were completed (using Revision 10 of the procedure), the reactor engineers confirmed the error and initiated CR 97-00546 to document it. Procedure Revision 11 was issued to correct the mistake, data was transferred from Revision 10, and the MTC values were recalculated. Calculations using both procedures yielded results that were within the TS surveillance limit (EOL MTC no more negative than -37 pcm per degree Fahrenheit change in RCS temperature). However, the MTC calculated in Revision 10 was

non-conservative (more margin between it and the TS limit). Further review by engineering personnel discovered that the procedural error had existed since plant operating cycle number 3, when xenon reactivity was first incorporated into the calculation. Recalculations conducted during this inspection period showed that the error resulted in less conservative calculations of the MTC in the previous two operating cycles (cycles 5 and 6) and conservative calculations in the previous cycles. The calculations became increasingly less conservative with each operating cycle, introducing an error approaching two pcm per degree change in the RCS by cycle 7. However, none of the previous cycles' recalculated values exceeded the TS limits.

While the above error did not result in the licensee exceeding any TS limiting conditions of operation, the inspector considered it significant because, if left uncorrected, it could have resulted in a non-conservative MTC calculation potentially affecting TS compliance, or worse, challenging the maximum negative MTC value assumed in the FSAR Chapter 15 main steam line break accident analysis (the limiting design basis accident for which MTC is considered). This error was also significant because it existed over six years involving at least six procedure revisions without being previously identified by plant staff. Technical Specification 6.8.1.a and Regulatory Guide 1.33, Appendix A, Section 8.b require specific implementing procedures for each surveillance test listed in the Technical Specifications. The failure to have an adequate procedure for correctly calculating the MTC value is considered a violation of TS 6.8.1.a and is identified as Violation 50-400/97-01-04.

c. Conclusions

Except for the procedural error associated with calculating the MTC, plant performance during the test, including that of control room operators and chemistry technicians, was good. One violation was identified for an inadequate test procedure.

M7.1 Maintenance Rule Expert Panel Meeting

a. Inspection Scope (62707,92902)

The inspector observed the Maintenance Rule Expert Panel Meeting conducted on February 5, 1997 to determine if the meeting was conducted in accordance with procedure ADM-NGGC-0101, Maintenance Rule Program, Revision 4.

b. Observations and Findings

The inspector observed that the composition of the expert panel met the requirements of the procedure. The subjects being discussed related to interface valves between safety and non-safety related systems, in relation to Violation 50-400/96-09-02. These included the Boron Thermal Regeneration System (BTRS), Nitrogen Supply System, Filter Backwash System, Boron Recycle System, HVAC Waste Processing Building, Oily Waste

Collection, Potable Water, and the Penetration Pressurization System. The discussion was generally good. However, the problem with these valves not being in the maintenance rule was identified 6 months earlier as a result of the inspector's findings on another valve. The inspector observed that there were no system engineers present at the meetings since a specific system engineer had not been assigned. The engineering supervisor responsible for those systems was also not at the meeting.

An item relating to BTRS was brought up in relation to its function for reactivity control. An action item was taken to review this function for inclusion at a later date in the Maintenance Rule. The inspector observed that there was a reluctance to decide whether to put that function in the Maintenance Rule. Sufficient systems knowledge was contained by expert panel members to have made a decision on this item since the panel included a licensed Senior Reactor Operator (SRO), and two SRO certified engineers. The inspector discussed this reluctance with licensee management. On February 9, 1997 a dilution event occurred while accomplishing a vent and fill of the BTRS which confirmed why the system should be scoped in the maintenance rule. This event is discussed in section O1.6.

c. Conclusions

The inspector concluded that maintenance rule expert panel composition and knowledge was adequate. However, the panel was not always prompt in addressing maintenance rule responsibilities.

M8 Miscellaneous Maintenance Issues (90712,92902)

M8.1 (Open) LER 50-400/96-025-00: Procedure Deficiency Caused by Personnel Error Resulting in Failure to Perform Technical Specification Surveillance Testing on PORV Block Valve 1RC-115.

This LER described the failure to test Power Operated Relief Valve, Block Valve 1RC-115 during refueling outage 6 in 1995. This missed surveillance test constituted a violation of Technical Specification 4.3.3.5.2 and was cited as NRC Violation 50-400/96-11-02. The LER will remain open pending the licensee's completion of corrective actions which will include an assessment on procedures completed to support the upcoming refueling outage.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 General Comments (37551)

Engineering support for the operation of the plant was observed to be good during the inspection period, particularly during the forced outage from January 31 - February 1, 1997. The system engineers were routinely involved in resolving abnormalities found with plant equipment. The inspectors identified a rolling scaffold on the 305 foot elevation of

the reactor auxiliary building near both trains of safety related control room ventilation that had an indicated weight on the engineering evaluation lower than the actual weight. Engineering reevaluated the scaffolding, and determined that it was acceptable.

E3 Engineering Procedures and Documentation

E3.1 General Comments (37551)

During the inspector's review of engineering surveillance test procedure EST-702, Moderator Temperature Coefficient - End-of-Life Using the Boron Method, Revision 10, a violation was identified as discussed in section M2.2 of this inspection report. The violation involved an error resulting in the miscalculation of the effect of xenon on core reactivity. The error was significant because it existed over six core operating cycles and six procedure revisions. The inspectors concluded that the violation was the result of inattention to detail by the engineering staff in the procedure development and review process.

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 (284 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.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 General Comments (71750)

The inspector observed radiological controls during the conduct of tours and observation of maintenance activities and found them to be acceptable. Contaminated parts were found in the locked Emergency Air Lock entrance way by a health physics (HP) technician. The inspector observed that the HP technician was thorough and took appropriate actions. A contamination event in the reactor auxiliary building on

February 10, 1997 was handled well. The licensee decontaminated the area and individual involved.

P1 Conduct of Emergency Preparedness (EP) Activities

P1.1 Emergency Drills

a. Inspection Scope (71750)

The inspectors observed two licensee emergency preparedness training drills conducted on January 9, 1997 and January 16, 1997. The inspectors rotated between the Emergency Operations Facility (EOF), the Technical Support Center (TSC), the Operations Support Center (OSC), and the drill control room located near the TSC.

b. Observations and Findings

The simulator was not used for these training drills. The two drills were the first in a four-drill training session designed to train personnel assigned new positions. The four drills involved the same scenario of a fuel failure with a primary-to-secondary leak followed by an open steam generator power-operated relief valve.

Intermittent breaks were held every 60 to 90 minutes during the drill to do a learning critique. These critiques allowed the licensee to apply the lessons learned in the early part of the drill into the rest of the drill. The licensee critiques were good and generated many issues.

c. Conclusions

The drill scenario was challenging and offered the licensee personnel a chance to train in a controlled environment. The licensee critiques were good and showed good self assessment capabilities. Management's decision to conduct these training drills and the decision to break intermittently for critiques was considered a strength.

P4 Staff Knowledge and Performance in EP

P4.1 Security Alert

a. Inspection Scope (93702)

The inspector observed the response to a security alert declared on January 22, 1997. The security alert was declared due to a cut wire in the motor control cabinet for the turbine building vent stack radiation monitor.

b. Observations and Findings

Maintenance personnel found a cut wire in the motor control cabinet for the turbine building vent stack radiation monitor at 1:25 p.m. The wire had been pulled out of a wiring bundle, cut, twisted together, and left

in the front part of the panel. Security declared a Security Alert at 2:00 p.m. based on the cut wire and that tampering could not be ruled out. The inspector observed the Security Manager communicate with the control room, fill out the NRC Event Notification Worksheet, and send it to the Main Control Room at 2:16 p.m. The NRC was notified of the physical security event under 10 CFR 73.71 at 2:25 p.m. A Security guard was posted at the motor control panel, personnel access entries to the protected area were reviewed, and a search of the protected area was conducted. No unauthorized entries were identified and no unauthorized personnel were found. The inspector observed that security personnel response to this event was good.

Plant Emergency Procedure (PEP) 110, Emergency Classification and Protective Action Recommendations, Revision 1, contains the emergency plan implementing procedure requirements. The operations shift superintendent had worked through the Emergency Action Level (EAL) Flow Path from PEP-110 with the Security Manager prior to the 2:25 p.m. NRC notification. The understanding of the shift superintendent was that a Security Emergency had not been declared, and therefore the flow path (side 1) did not require an EAL flow path declaration. In discussing the security event classification at approximately 3:00 p.m. with the inspector, the shift superintendent found out that a Security Alert had been declared. He immediately confirmed this with the Security Manager and at 3:05 p.m. declared a Notice of Unusual Event (NOUE). This was based on a Security Alert being identified in the NOUE Matrix at the bottom of the EAL Flow Path page.

Although the NRC Event Notification Worksheet sent from Security to the Main Control Room did not identify that the event had been classified as a Security Alert, the licensee determined that the shift superintendent had sufficient information communicated to him to have declared an NOUE at the time of the 10 CFR 73.71 declaration and notification (2:25 p.m.). The licensee initiated Condition Reports 97-00300 and 97-00302 with corrective action that included the involved shift superintendent receiving counseling, the involved shift superintendent distributing a memorandum of lessons learned from this event (dated February 6, 1996), and procedure changes that link events to EALs in the associated procedures. This failure to declare an NOUE per procedure PEP-110 is considered a violation of TS 6.8.1.c for failure to follow Emergency Plan implementation procedures.. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with section VII.B.1 of the Enforcement Policy (NCV 50-400/97-01-05)

The shift superintendent notified the NRC of the NOUE declaration at 4:08 p.m. This declaration was made three minutes after the required one hour notification time required by 10 CFR 50.72 and contained in Procedures PLP-201, Emergency Plan, Revision 29, and PEP-310, Notifications and Communications, Revision 3. The late notification was obvious to all in the Main Control Room, including the shift superintendent and was also identified to the NRC through a 10 CFR 50.72 event update notification transmitted to NRC at 11:43 p.m. The inspector observed that the shift superintendent waited until

approximately 5-10 minutes prior to the end of the one hour period to begin preparing for the notification. Initial NRC notification at 2:25 p.m. had resulted in the NRC asking several questions. The answers to those questions were coming in about 5 minutes prior to the notification expiration time. The inspector observed that the shift superintendent was attempting to revise his prepared report to include the requested information at the one hour point. The failure to provide a prompt report for event classification was partially mitigated by the fact that the notification promptly made under 10 CFR 73.71 at 2:25 p.m. provided the NRC with initial information necessary to begin evaluation of the event. The licensee initiated Condition Report 97-00304 with corrective action that included the involved shift superintendent receiving counseling and the involved shift superintendent distributing a memorandum of lessons learned from this event (dated February 6, 1996) to other operations personnel. The failure to report the NOUE within the required time frame specified in PLP-201 and PEP-310 was considered a violation of TS 6.8.1.c for failure to follow Emergency Plan implementation procedures. This licensee-identified and corrected violation is being treated as a second example of the Non-Cited Violation discussed above and is consistent with section VII.B.1 of the Enforcement Policy (NCV 50-400/97-01-05)

P4.2 Boron Dilution Event

a. Inspection Scope (71707)

The inspectors observed the response to a boron dilution event that occurred on February 9, 1997 as discussed in Section 01.6.

b. Observations and Findings

The inspector found that the Emergency Action Level flow path contained in Plant Emergency Procedure (PEP) 110, Emergency Classification and Protective Action Recommendations, Revision 1, identified an initiating event as an Uncontrollable Boron Dilution. The inspector did not find any specific guidance in licensee procedures that define the initial criteria for this event. If the uncontrollable boron dilution was answered yes, the criteria for declaring an "Alert" was a dilution event lasting greater than 15 minutes. The licensee included a corrective action in Condition Report 97-00703 to revise the EAL flow path to provide a better definition for an uncontrollable boron dilution.

P4.3 Conclusions

The inspector concluded that operator response to the events that occurred this period in relation to emergency preparedness was mixed. The dilution event was responded to well, while a late declaration and notification characterized the security event (NCV 50-400/97-01-05).

S1 Conduct of Security and Safeguards Activities

S1.1 General Comments (71750)

The inspector observed security and safeguards activities during the conduct of tours, observation of maintenance activities, during a declared security alert, and the emergency preparedness drill, and found them to be good. Compensatory measures were posted when necessary and properly conducted.

S1.2 Security Alert (93702)

The inspector observed the security department response to the event described in Section P4.1. The licensee's critique found that communication between the security manager and the operations shift superintendent could have been improved. The inspector found that security personnel response to this event was good.

F1 Control of Fire Protection Activities

F1.1 General Comments (71750)

The inspector observed fire protection equipment and activities during the conduct of tours and observation of maintenance activities and found them to be acceptable. One fire hose station and two fire extinguishers were found on February 5, 1997 in the fuel handling building with new unpunched 1997 inspection tags that did not indicate their monthly inspection in January 1997. The licensee determined the equipment had been inspected but the tags had not been punched. However, the licensee reinspected this equipment, found it to be satisfactory, and updated the tags.

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 February 21, 1997. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

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. Donahue, Director Site Operations, Harris Plant
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
T. Morton, Acting Superintendent, Mechanical Systems
K. Neuschaefer, Superintendent, Radiation Protection
W. Peavyhouse, Superintendent, Design Control
W. Robinson, Vice President, Harris Plant
G. Rolfson, Manager, Harris Engineering Support Services
S. Sewell, Manager, Operations
D. Tibbitts, Acting Manager, Nuclear Assessment
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 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62700:	Maintenance Implementation
IP 62707:	Maintenance Observation
IP 71001:	Licensed Operator Requalification Program Evaluation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 90712:	In-Office Reviews of LERs
IP 92700:	Onsite Followup of Events
IP 92901:	Followup - Plant Operations
IP 92902:	Followup - Maintenance
IP 93702:	Onsite Response to Events In Office Review

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-400/97-01-01	URI	Tracking Operator License Conditions in the MCR (paragraph O1.2).
50-400/97-01-02	NCV	Failure to comply with TS 3.6.3 (paragraph O8.1).
50-400/97-01-03	VIO	Inadequate corrective action pertaining to LER 96-003-00 for core flux mapping (paragraph O8.3).
50-400/97-01-04	VIO	Failure to have an adequate procedure for correctly calculating the Moderator Temperature Coefficient (paragraph M2.2).
50-400/97-01-05	NCV	Failure to follow Emergency Plan implementation procedures (paragraph P4).
50-400/96-025-00	LER	Procedure deficiency caused by personnel error resulting in failure to perform Technical Specification surveillance testing on PORV Block Valve 1RC-115 (paragraph M8.1).

Closed

50-400/96-003-00	LER	Failure to perform core flux mapping following short power excursions over 100 percent (paragraph O8.3).
50-400/96-006-00	LER	Main feedwater isolation valve 1FW-277 valve stem to disc failure (paragraph O8.1).

50-400/96-04-02	VIO	Inadequate corrective action for resin spill and reactor switchgear voltmeter deficiency (paragraph 08.2).
50-400/97-01-02	NCV	Failure to comply with TS 3.6.3 (paragraph 08.1).
50-400/97-01-05	NCV	Failure to follow Emergency Plan implementation procedures (paragraph P4).