UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos.: 50-400/87-37

Licensee: Carolina Power and Light Company
P. O. Box 1551
Raleigh, NC 27602

Docket No.: 50-400 License No.: NPF-63

Facility Name: Harris 1

Inspection Conducted: September 24 - October 27, 1987

Inspectors: S. J. Vias for G. F. Maxwell — 11/10/87 Date Signed

S. J. Vias for S. P. Burris — 11/10/87 Date Signed

Approved by: P. E. Fredrickson, Section Chief, Division of Reactor Projects — 11/10/87 Date Signed

SUMMARY

Scope: This routine, announced inspection involved inspection in the areas of Operational Safety Verification, Monthly Surveillance Observation, Monthly Maintenance Observation, Onsite Nuclear Safety Committee and AFW Logic Deficiency.

Results: Two violations were identified - "Operators Manipulating Valves Which Were Known to Operate in an Unsafe Manner" - Paragraph 3.e and "AFW Logic Design Deficiency" - paragraph 7.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

G. G. Campbell, Manager of Maintenance
J. M. Collins, Manager, Operations
G. L. Forehand, Director, QA/QC
L. I. Loflin, Manager, Harris Plant Engineering Support
G. A. Myer, General Manager, Milestone Completion
D. L. Tibbitts, Director, Regulatory Compliance
R. B. Van Metre, Manager, Harris Plant Technical Support
R. A. Watson, Vice President, Harris Nuclear Project
J. L. Willis, Plant General Manager, Operations

Other licensee employees contacted included technicians, operators, mechanics, security force members, engineering personnel and office personnel.

2. Exit Interview

The inspection scope and findings were summarized on October 27 and November 6, 1987, with the Plant General Manager, Operations. No written material was provided to the licensee by the resident inspectors during this reporting period. The licensee did not identify as proprietary any of the materials provided to or reviewed by the resident inspectors during this inspection. The violation identified in this report has been discussed in detail with the licensee. The licensee provided no dissenting information at the exit meeting.

3. Operational Safety Verification (71707, 71710)

a. Plant Tours

The inspectors conducted routine plant tours during this inspection period to verify that the licensee's requirements and commitments were being implemented. These tours were performed to verify that systems, valves and breakers required for safe plant operations were in their correct position; fire protection equipment, spare equipment and materials were being maintained and stored properly; plant operators were aware of the current plant status; plant operations personnel were documenting the status of out-of-service equipment; security and health physics controls were being implemented as required by procedures; there were no undocumented cases of unusual fluid leaks, piping vibration, abnormal hanger or seismic restraint movements; and all reviewed equipment requiring calibration was current.

Tours of the plant included review of site documentation and interviews with plant personnel. The inspectors reviewed the shift foreman's log, control room operator's log, clearance center tag out logs, system status logs, chemistry and health physics logs, and control status board. During these tours the inspectors noted that the operators appeared to be alert and aware of changing plant conditions.

The inspectors evaluated operations shift turnovers and attended shift briefings. They observed that the briefings and turnovers provided sufficient detail for the next shift crew.

The inspectors verified that various plant spaces were not in a condition which would degrade the performance capabilities of any required system or component. This inspection included checking the condition of electrical cabinets to ensure that they were free of foreign and loose debris, or material.

Site security was evaluated by observing personnel in the protected and vital areas to ensure that these persons had the proper authorization to be in the respective areas. The security personnel appeared to be alert and attentive to their duties and those officers performing personnel and vehicular searches were thorough and systematic. Responses to security alarm conditions appeared to be prompt and adequate.

b. Inoperable NRC Emergency Notification System

On September 24, the control room shift foreman found the NRC Event Notification Network (red telephone) was not working when he attempted to use it; however, plant conditions were not impacted by the inoperable telephone. The shift foreman reported the condition to the NRC duty officer by using the site telephone system. On September 25, the red telephone was repaired and returned to service. The malfunction was attributed to electrical problems with the network circuits in the Washington, D.C. area.

c. Mechanical Failure of the Main Feedwater Recirculation Valve

On September 25, the plant reported an unplanned actuation of the auxiliary feedwater system. The event occurred while the plant was in Hot Standby with a plant heatup in progress. During the heatup, the main feedwater was being supplied by the "A" main feedwater pump. The "A" main feedwater pump recirculation valve stem (1-FW-8) broke, causing the valve to fail in a closed position. When the recirculation valve failed in the closed position, the main feedwater pump was essentially pumping against a shut off discharge flow path. The "A" main feedwater pump then tripped on low flow, to protect the pump from becoming damaged. The auxiliary feedwater system then automatically started due to the engineered safety feature circuitry sensing that both main feedwater pumps were tripped and the auxiliary

feedwater pump control switches were in the "auto" position. The two motor-driven auxiliary feedwater pumps started as required and the control room operators stabilized the plant parameters. The cause of the event was investigated and a Work Request (WR/87-BDIP1) was initiated to replace the broken valve stem. The "B" main feedwater pump was started and the plant heatup continued.

d. Failure of the ERFIS Plant Computer

On September 27, at 2:03 p.m., the licensee declared an Unusual Event (UE) as a result of the loss of the Emergency Response Facility Information System (ERFIS) plant computer. The system failure was attributed to the data disks failing on both the "A" and "B" computers. This failure had no immediate impact on the safe operation of the plant. The control room notified the state, local and NRC officials. The computers were repaired and the UE was terminated at 3:02 p.m.

e. Unusual Event - Vent System for the Reactor Coolant Loop

On October 9, the NRC Duty Officer was notified of an Unusual Event (UE) which had been declared by the licensee at 6:10 a.m. The UE was declared as the result of an apparent malfunction of valves on the reactor coolant system head vent system (RCSHVS). The valves malfunctioned while conducting an Operations Surveillance Test, OST-1043, "Reactor Coolant System Vent Path Operability, Quarterly Interval". The OST allowed opening only one valve at a time to prevent a flow path out of the reactor coolant system (RCS). However, due to the design of the valves and the test sequence, the test resulted in the inadvertent actuation of the two valves in series, allowing reactor coolant to vent to the pressurizer relief tank (PRT) and to the containment atmosphere. Throughout the event, the plant was operating at approximately 91 percent power (Mode 1).

The inspectors interviewed the personnel on shift at the time of the test, and other licensee personnel, and evaluated the licensee's preliminary incident report and established the sequence of events. The valves discussed below are identified on site drawing CPL-2165-S-1301. Each of the valves are of identical design and are solenoid actuated, pilot operated globe valves manufactured by Target-Rock. The normal expected cycle closing time for each valve is about two seconds. The chronology is presented in the following paragraphs.

Inservice inspection (ISI) personnel requested a test of selected valves (1RC-900, 901, 902 and 904) to quantify suspected valve degradation. Two other similar functioning valves, 1RC-903 and 1RC-905 did not have suspected degradation and, therefore, were not tested. The control switches for these valves have positions for "shut pull to lock", and "open". When not in "shut pull to lock", the switch spring returns to a neutral position. The control

switches for all six valves were in the "shut pull to lock" position which is normal for Power Operations (Mode 1). OST-1043 is the routine surveillance procedure for measuring valve response time, and it was used to test the selected valves. Permission to perform the test was granted by the shift foreman, as required by the procedure.

At approximately 5:00 a.m. on October 9, 1RC-904 was satisfactorily cycled. A few seconds later, 1RC-900 was opened and the operator observed that the position indication light for valve 1RC-904, which was in the "shut pull to lock" position, also gave an open indication. 1RC-900 was quickly shut and 1RC-904 immediately closed. The operators continued with the test, since they were able to immediately shut both 1RC-900 and 1RC-904. The shift foreman was not consulted about the opening of 1RC-904. The shift foreman was not in the control room at this time.

Due to the unexpected flicker of the open light for 1RC-904 and the prompt closing of 1RC-900, a response time for valve 1RC-900 was not obtained, and at 5:03 a.m. it was cycled again to obtain the response time. When 1RC-900 was cycled full open, both 1RC-904 and 1RC-905 opened. During an attempt to close the valves the control switches were put in the shut position momentarily and the valves remained open. (1RC-904 and 1RC-905 did not close because they had opened from upstream pressure, not the control switch). Up to this point, the evolution was being carried out by two senior reactor operators. Approximately 30 seconds after opening 1RC-900, the shift foreman returned to the control room, unaware of the event. Shortly thereafter, a third operator became involved as the first operators tried to close the three valves. The third operator stated that 1RC-900 would close if the control switch was held in the "shut" position until the valve indicated closed. This was done and all three valves closed; 1RC-904 and 1RC-905 closed immediately after 1RC-900 was observed to be closed. The licensee's best estimate of total time the valves were open is two minutes, based on computer stored data. Small changes in pressurizer level and pressure were observed while the valves were open.

Shift personnel then discussed the event in order to determine if it was safe to continue testing; this discussion lasted about ten minutes. Throughout the discussion, the shift foreman was unaware of the results from the first cycle of 1RC-900, which had occurred at 5:00 a.m. The items discussed were the need to proceed and quantify the response time of 1RC-900 and the balance of the untested valves, the confirmed ability to close a valve by holding the control switch in the "shut" position, and the fact that OST-1043 was the established, approved procedure for quantifying valve response times. The shift foreman concluded that it was safe to proceed with valve testing because of the demonstrated ability to close the valves. Further consultation with the next level of plant supervision was not done prior to proceeding with the testing.

The remaining valves were tested commencing at 5:15 a.m. and concluding at 5:21 a.m. Each time a vent valve (1RC-900, 901, or 902) was cycled, both block valves (1RC-904 and 905) indicated open. The results from the test were as follows:

- 1RC-900 was fully opened; 1RC-904 and 905 open lights came on. The operators immediately closed 1RC-900 after full open indication; 1RC-904 and 905 immediately closed. The closing stroke time was 5.2 seconds.

- 1RC-901 was fully opened; 1RC-904 and 905 open lights came on. The operators immediately closed 1RC-901 after full open indication ; 1RC-904 and 905 closed immediately. The closing stroke time was 1.0 second.

- 1RC-902 was fully opened; 1RC-904 and 905 open lights came on. The operators immediately closed 1RC-902 after full open indication; 1RC-904 and 905 closed. The closing stroke time was 9.7 seconds.

At approximately 5:20 a.m. the licensee completed a quick assessment of the amount of reactor coolant that had been lost during the testing. The amount was estimated to be about 150 gallons; a subsequent assessment in the licensee's preliminary incident report concluded the loss to be approximately 200 gallons. The majority of the loss was attributed to the second cycling of 1RC-900 (at 5:03 a.m.).

The shift foreman reviewed the Emergency Plan procedures, and concluded that declaration of an Unusual Event was appropriate. His decision was based on the fact that the Technical Specification limit for reactor coolant system leakage had been exceeded during that interval. The declaration was made and terminated effective 6:10 a.m. State and local officials were notified in accordance with the applicable procedures.

The licensee investigation of the event began during the morning of October 9. The investigation involved the manager-operations, the operations supervisor and the shift foreman, who was recalled to the site. The investigation included a review of the logs and records from the event, interviews with selected members of the shift crew and a technical evaluation of the response of the valves.

The investigation concluded that the actions by the operators to proceed with OST-1043 resulted in a challenge to the capability to maintain adequate water inventory for the reactor coolant system and that prompt measures were required to address this incorrect personnel decision. The oncoming shift (at 6:00 p.m. on October 9) was briefed by plant management on the event and the errors made during the testing of the RCSHVS valves. These presentations were made by the plant general manager, the manager-operations, and the

operations supervisor. Each shift attended similar briefings prior to assuming a watch.

The shift foreman involved in the incident was counseled on the seriousness of the incident by the manager-operations, operations supervisor, and separately by the plant general manager. The shift foreman was also required to assist in the incident investigation and to participate in the briefings for shift personnel.

The licensee also initiated a task force to investigate the operation of the valves. Shortly after contacting Target-Rock, the valve manufacturer, the licensee learned that the behavior of the block valves (1RC-904 and 905) had been observed at other plants. A technical paper was published by ASME, addressing the likelihood of this valve behavior. The paper is titled, "Spurious Opening of Hydraulic-Assisted, Pilot Operated Valves - An Investigation of the Phenomenon", and was published as ASME Publication 81-BVP-39 in April 1981. The licensee determined that this information had not been available to the Shearon Harris site staff prior to this event.

As a result of the technical review, it was determined that actuating 1RC-904 before operating 1RC-900, 901, 902 or 903 could result in the formation of an air pocket above the plug in the valve. The air pocket could cause the valve to come off of its seat when shocked with a sudden pressure surge from the opening of an upstream valve. Also the control circuit for 1RC-904 would allow the valve to remain in the open position if the control switch was in the "normal" position, when the valve came off its seat. A technical evaluation concluded that by physically rotating the valve body so that the solenoid was below the horizontal, could prevent the formation of an air pocket. Subsequently the licensee changed the sequence of valve testing in OST-1043 to caution operators to open the downstream valves last (OST-1043 Temporary Change #7016, dated October 19). Because of the consequences of valve failure, the licensee is also pursuing ISI relief and a Technical Specification change to decrease the testing frequency in order to avoid cycling of these valves while the reactor coolant system is pressurized. The licensee's plans are to complete the procedure changes and design changes prior to start-up from the current outage. The licensee has conducted on-shift training so that shift personnel are aware of the technical details on the valves' inadvertent operation.

The event was caused in part by the actions of the shift personnel in carrying out their responsibilities as licensed operators. Specifically, Technical Specification 6.8.1a requires that plant operations be controlled in accordance with administrative procedures. The plant procedure OMM-001, Rev. 3, "Operations - Conduct of Operations", step 3.2.3.4 requires that the plant be operated in a safe manner at all times. The action to proceed with the testing of RCSHVS valves after the 5:03 a.m. event on October 9th

was not in accordance with the requirements of OMM-1 as described above.

This is a violation, "Operators Manipulating Valves Which Were Known to Operate in an Unsafe Manner", 50-400/87-37-01.

f. 1A-SA Electrical Bus Blackout

On October 10 the plant experienced an automatic start of the 1A-SA emergency diesel generator after loss of the 1A-SA electrical safety bus. The diesel generator automatically started and picked up the required "A" train loads. When this event occurred the plant was in Cold Shutdown and had just begun a plant outage. Implementation of a modification had required personnel to deenergize one of the two parallel lines for the "A" start-up transformer to allow the installation of a new electrical cable to the switch yard from the relay cabinet. While performing the work inside the cabinet (hammering and drilling), licensee personnel inadvertently jarred protection relays causing a trip of the remaining breaker for the "A" start-up transformer, resulting in an "A" bus blackout. The licensee restored offsite power and secured the diesel generator. All equipment functioned as designed with the exception of the "A" emergency service water screen wash pump which did not start when the diesel generator assumed the bus loads. The licensee is investigating this event and the inspectors will follow up on this event during a future inspection.

g. Failure of the RHR Suction Valve Interlock

On October 15, while the plant was in Mode 5 (Cold Shutdown), the "B" train suction, 1RH-1 and 1RH-39, valves in each RHR loop suddenly closed. The running RHR pump was stopped by the operators to prevent the pump from being damaged. The first event of this type happened at about 7:40 a.m., and the second event occurred at 9:22 p.m. The RHR suction valves were shut for only fifteen minutes during the last event, and for less than five minutes during the first event. The inspectors reviewed the TS Action Statement 3.4.1.4.1, observed the plant condition, which was Cold Shutdown, and determined that the licensee complied with the applicable action statement. The licensee reported these occurrences to the NRC duty officer on October 16 as a requirement of 10 CFR 50.72, using NUREG 1022 as a guide. The first event was reported to the NRC duty officer as having occurred due to an electrical spike caused by the technicians who were performing a test on the interlocks for the two RHR suction valves. The test was being conducted to satisfy the requirements of Surveillance Test OST-1071, Rev. 0, Step 7.1. This test required lifting the electrical leads in the process instrumentation control cabinets to prevent the automatic closure of residual heat removal (RHR) valves RH-1, RH-2, RH-39 and RH-40. The inspectors interviewed the technicians and were informed that as of October 23 the cause of the valves' closure was yet to be determined, and is still under

evaluation by the licensee. The licensee plans to complete this evaluation prior to returning the plant to power operation. The technicians also stated that they had repeated all of the steps of OST-1071, starting from Step 7.1.c, and as part of the further evaluation they will rerun the entire Step 7.1.

The next time the two RHR suction valves closed, at 9:22 p.m., the cause was attributed to the failure of the test instrument which was being used during the OST. The instrument was found to have weak batteries, which had apparently discharged during the test's duration. The discharged batteries caused the test instrument output to be low. The low output signal allowed the closing circuit for the "B" train RHR pump suction valves to actuate, and the valves closed. After the operating RHR loop was returned to service the OST was continued. The instrument was replaced with one that had fully charged batteries and the test was completed successfully.

One violation was identified in the areas inspected.

4. Monthly Surveillance Observation (61726)

The inspectors witnessed the licensee conducting maintenance surveillance test activities on safety-related systems and components to verify that the licensee performed the activities in accordance with licensee requirements. These observations included witnessing selected portions of each surveillance, review of the surveillance procedure to ensure that administrative controls were in force, determining that approval was obtained prior to conducting the surveillance test and the individuals conducting the test were qualified in accordance with plant-approved procedures. Other observations included ascertaining that test instrumentation used was calibrated, data collected was within the specified requirements of Technical Specifications, any identified discrepancies were properly noted, and the systems were correctly returned to service. The following specific activities were observed:

During this inspection period the licensee requested exigency on a Technical Specification change request for Surveillance Requirement 4.8.1.1.2.f.11. As verified by the licensee's procedure OST-1824, this surveillance currently ensures that during a load rejection test, emergency diesel generator voltage does not exceed a maximum of 7590 volts. The licensee requested that this surveillance requirement be changed to reflect a 110 percent value of the voltage at the start of the test. The original specification stipulates that "verifying the generator capability to reject a load of between 6200 and 6500 kW without tripping. The generator voltage shall not exceed 7590 volts during and following the load rejection". This surveillance is performed to verify that a load rejection of the diesel generator does not generate an overspeed trip and that the voltage regulator functions correctly, ensuring the diesel generator is available immediately following a load rejection. The 7590 voltage limit is based on 110 percent of nominal generator starting voltage of 6900 volts. During the most recent test conducted on

October 13, the licensee experienced problems with meeting the maximum voltage limit of 7590 volts. With the generator connected to the grid, voltage of the generator must be maintained greater than system grid voltage to ensure proper operation of emergency diesel generator within its design limits. Therefore initial generator starting voltage was greater than the 6900 volts (approximately 7350 volts) due to low system grid demand (higher system grid voltage). Starting at this higher initial voltage of 7350 volts the maximum voltage reached 7850 volts, exceeding the TS limit of 7590 volts. However, the voltage did not exceed 110 percent (8085 volts) of the initial starting voltage of 7350 volts. The licensee reviewed this specification and requested that the NRC approve a change to TS 4.8.1.1.2.f.11 which would limit the generator voltage to less than or equal to 110 percent of the voltage on the generator at the start of the test. The licensee has provided a detailed analysis to the NRC for review prior to approval of this TS change. The resident inspectors will continue to monitor the status of this change request in future inspection periods.

No violations or deviations were identified in the areas inspected.

5. Monthly Maintenance Observation (62703, 62700, 37700)

The inspectors reviewed the licensee's maintenance activities during this inspection period to verify the following: maintenance personnel were obtaining the appropriate tag out and clearance approvals prior to commencing work activities, correct documentation was available for all requested parts and material prior to use, procedures were available and adequate for the work being conducted, maintenance personnel performing work activities were qualified to accomplish these tasks, no maintenance activities reviewed were violating any limiting conditions for operation during the specific evolutions, the required QA/QC reviews and QC hold points were implemented, post-maintenance testing activities were completed, and equipment was properly returned to service after the completion of work activities.

The inspectors obtained copies of several Plant Change Requests (PCR) and the applicable Work Request (WR) for each specific PCR. These documents were reviewed to ensure that the PCR had been generated in accordance with the appropriate engineering document, evaluated technically and administratively by the authorized groups and that personnel implementing these PCRs were qualified in accordance with the licensee's procedures. Specific details of each PCR reviewed are as follows:

- PCR-2171 - Main Feedwater Pump Total Discharge Head Reduction. Secondary perturbations have caused numerous oscillations of high discharge pressure and low suction pressure trips of the pumps and subsequent plant trips since the start-up of the Harris plant. These instabilities in the feedwater system have usually resulted in poor feedwater control valve response and operation which in some cases lead to trips of the main feedwater pumps (MFP) and condensate booster pumps. The licensee and pump vendor have reviewed these

problems in detail and determined proper operation of these control valves could be obtained by reducing the discharge pressure of the MFP. The licensee issued two WRs for each MFP, 87-BCJQ1 and 87-BCJQ2 for MFP 1A and 87-BCJR1 and 87-BCJR2 for MFP 1B. These WRs implemented PCR-2171 which required machineing the MFP implemented to reduce the total discharge pressure by approximately 15 percent in total discharge head. The inspectors witnessed the disassembly and reassembly of the MFPs as authorized by WR 87-BCJQ2 and 87 BCJR2 for MFP 1A and 1B respectively. The licensee plans on completing post maintenance testing and design verification prior to declaring the main feedwater system and control valves operable.

- PCR-2173 - Heater Drain Pump (HDP) Impeller Removal. Due to the previously identified secondary plant pressure response problems the licensee investigated actions necessary to make the heater drain system more reliable. Field investigation of these pressure problems found that by throttling the manual isolation valve upstream of the HDP level control valve provided a pressure drop (approximately 80 pounds per square inch) reducing the likelihood that a sudden pressure change could adversely affect the heater drain system. Discussions between the licensee and vendor (Ingersoll-Rand) concerning pump operability and design capabilities found that this 80 psi drop was approximately equal to one stage of the HDP. Therefore, the vendor recommended that the pump be modified by removing the last stage which would reduce the total discharge head by the necessary pressure. Removal of the sixth stage from the pump necessitated installing a flanged volute extension which would direct discharge flow out of the pump to the discharge piping. WR documentation to implement and perform the necessary work activities were issued, performed and are in the review process at this time. These WRs are identified as 87-BCBN1 and 87-BCBS1 for HDP 1A and 1B respectively. The inspectors witnessed the removal of the sixth stage and replacement with the required spool piece. Final acceptance of this modification by the licensee will be performed prior to end of the outage.

- PCR-1829 - Feedwater Recirculation Orifices. This PCR modified the MFP recirculation lines and logic for the main feedwater flow control valves (FCV). The licensee found that the downstream side of the MFP feed line orifices were experiencing cavitation due to a sudden pressure drop prior to entering the main condenser. This condition lead to recirculation flow control problems with the system as designed. The licensee was in the process of implementing changes to the MFP lines and control logic as follows; installation of additional restrictive orifices downstream of the FCV which will reduce flashing upstream of the orifice. These orifices will also limit the amount of recirculation flow returning to the condenser when the FCV's are full open. FCV logic was changed from "open" and "modulate" to that of "closed" and "auto". This logic change will allow opening of the FCV when the MFP flow drops to 4300 gpm and will close the FCVs when MFP flow reaches 8600 gpm. Due to the new

orifice sizing, when the FCV's are full open 4300 gpm of MFP flow will return to the condenser, yet still maintaining MFP flow at 8600 gpm. This 4300 gpm will prevent FCV cycling excessively while ensuring that MFP minimum flow requirements are met. The licensee conducted these changes in accordance with WRs 87-BELK1, 87-BELK2, 87-BELN1 and 87-BELN2.

No violations or deviations were identified in the areas inspected.

6. Onsite Nuclear Safety Committee (40700)

With the plant in Mode 4 (Hot Shutdown), operating on RHR shutdown cooling, the plant experienced a reactor protection system actuation. The event occurred while the licensee was implementing PCR-2292, modification on auxiliary feedwater control logic. Review of this PCR was performed and approved by the Plant Nuclear Safety Committee prior to technicians attempting to install these modifications. When Instrumentation and Control technicians removed power from Card 8 in Process Instrumentation and Control (PIC) Cabinet 4, bistable P-13 (input for turbine power greater than 10 percent) deenergized enabling the associated turbine trip/reactor trip to activate causing the plant to experience a reactor trip. Licensee personnel informed the inspectors that it was believed that the input to the turbine trip/reactor trip (first stage turbine pressure) would fail low on loss of power and not activate the P-13 bistable. Subsequent licensee investigation into the electrical drawings found that the P-13 bistable would in fact initiate when the power for Card 8 in PIC 4 was removed. NRC inspectors, performing a special inspection during the week of October 19, 1987, obtained a copy of PCR-2292 for review as a part of this inspection efforts. The results of this review will be documented in a subsequent inspection report.

No violations or deviations were identified in the areas inspected.

7. AFW Logic Deficiency (36100)

NRC personnel evaluated an event which the licensee reported in accordance with 10 CFR Part 21. This Part 21 event was identified in September, 1987 during evaluation of an unrelated event, discussed in Inspection Report 50-400/87-34. The issue dealt with a design review of a postulated accident in which the loss of a vital DC bus (1B-SB) was concurrent with loss of preferred (offsite) power. The licensee's evaluation of this item determined that this situation, of its self, did not result in any unanalyzed design condition. However, while performing this analysis, the licensee found three other accident scenarios which needed to be evaluated and resolved. These three scenarios are as follows:

Scenario I: The loss of vital DC bus 1B-SB coincident with a loss of off-site power causes loss of one motor driven AFW pump and the turbine driven AFW pump.

Scenario II: The inadvertent actuation of a relay causes isolation of AFW flow to one intact steam generator.

Scenario III: The loss of vital DC bus 1B-SB coincident with a loss of off-site power allowed the Engineered Safeguard Feature Actuation System to isolate AFW from all three steam generators.

After performing engineering design reanalyses, the licensee submitted a letter on September 22, 1987, outlining the results of these reviews to the NRC. Details of this letter identified that two of the three scenarios (I & II) were encompassed by the FSAR, Chapter 15 acceptance criteria. In scenario III, the licensee implemented wiring changes to the auxiliary feedwater system control and logic to ensure reliable operation of this system under all conditions. Subsequent correspondence from the licensee, to the NRC, on October 9, stipulated that none of the scenarios previously mentioned were considered to be design basis events, based on the licensees interpretation of the applicable IEEE standards.

NRC review and evaluation of the submitted documents has found that scenario III was, in fact, a design basis event for which the licensee should have previously identified and evaluated. This failure to analyze and design for this scenario is a violation of 10 CFR 50, Appendix A, Criteria 44, Cooling Water, which requires that, for the AFW cooling system "Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure." In scenario III, with the loss of offsite power, the additional loss of the DC bus is the single failure, resulting in isolation of all AFW. This issue is identified as a violation, "AFW Logic Design Deficiency," 50-400/87-37-02.

One violation was identified in the areas inspected.