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

Report No.: 50-261/90-30

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

Docket No.: 50-261 License No.: DPR-23

Facility Name: H. B. Robinson

Inspection Conducted: December 11, 1990 - January 10, 1991

Lead Inspector: K. C. Carroll for 2/1/91
L. W. Garner, Senior Resident Inspector Date Signed

Other Inspector: K. R. Jury

Approved by: H. O. Christensen 2/1/91
H. O. Christensen, Section Chief Date Signed
Reactor Projects Branch 1
Division of Reactor Projects

SUMMARY

Scope:

This routine, announced inspection was conducted in the areas of operational safety verification, surveillance observation, maintenance observation, refueling activities and action on previous inspection findings.

Results:

A violation was identified involving an inadequately established preventive maintenance procedure for inspection of the residual heat removal system pump discharge check valves (paragraph 4).

The ultrasonic surface reflectors on the A steam generator upper girth weld were determined (by visual and fluorescent magnetic particle inspections) not to be similar to those associated with rapid crack propagation occurring in other utilities' steam generators (paragraph 6).

The actual 1990 radiological exposure of 437 Person-Roentgen Equivalent Man (REM) was less than the 450 Person-REM goal established at the beginning of 1990 (paragraph 2).

The component cooling water piping to the residual heat removal pump seal coolers ruptured during a hydrostatic test. The probable root cause was attributed to rain or other external water intrusion between the piping and thermal insulation, resulting in extensive external corrosion of the carbon steel pipe (paragraph 2).

Extensive service water system inspection, repairs, and component refurbishment/replacement were performed during the refueling outage (paragraph 2).

Strong communications and interfacing was evident between Technical Support and Nuclear Engineering Department on both the service water system efforts and the A steam generator indications resolution (paragraphs 2 and 6).

Fourteen spent fuel assemblies have been shipped from the site to the Harris Nuclear Facility in North Carolina (paragraph 6).

All control rod guide tube support pins have been replaced with a redesigned pin which is less susceptible to intergranular stress corrosion cracking (paragraph 6).

REPORT DETAILS

1. Persons Contacted

*R. Barnett, Manager, Outages and Modifications
C. Baucom, Shift Outage Manager, Outages and Modifications
J. Benjamin, Shift Outage Manager, Outages and Modifications
C. Bethea, Manager, Training
*W. Biggs, Manager, Nuclear Engineering Department Site Unit
S. Billings, Technical Aide, Regulatory Compliance
R. Chambers, Manager, Operations
*D. Crook, Senior Specialist, Regulatory Compliance
*J. Curley, Manager, Environmental and Radiation Control
*C. Dietz, Manager, Robinson Nuclear Project
D. Dixon, Manager, Control and Administration
J. Eaddy, Supervisor, Environmental and Radiation Support
S. Farmer, Supervisor - Programs, Technical Support
R. Femal, Shift Foreman, Operations
*W. Gainey, Plant Support
E. Harris, Manager, Onsite Nuclear Safety
*J. Kloosterman, Director, Regulatory Compliance
D. Knight, Shift Foreman, Operations
E. Lee, Shift Outage Manager, Outages and Modifications
A. McCauley, Supervisor - Electrical Systems, Technical Support
R. Moore, Shift Foreman, Operations
D. Nelson, Shift Outage Manager, Outages and Modifications
*M. Page, Manager, Technical Support
D. Seagle, Shift Foreman, Operations
*J. Sheppard, Plant General Manager
*R. Smith, Manager, Maintenance
R. Steele, Shift Foreman, Operations
D. Winters, Shift Foreman, Operations
*H. Young, Director, Quality Assurance/Quality Control

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

*Attended exit interview on January 15, 1991.

Acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Operational Safety Verification (71707)

The inspectors evaluated licensee activities to confirm that the facility was being operated safely and in conformance with regulatory requirements. These activities were confirmed by direct observation, facility tours, interviews and discussions with licensee personnel and management, verification of safety system status, and review of facility records.

To verify equipment operability and compliance with TS, the inspectors reviewed shift logs, Operations' records, data sheets, instrument traces, and records of equipment malfunctions. Through work observations and discussions with Operations staff members, the inspectors verified the staff was knowledgeable of plant conditions, responded properly to alarms, adhered to procedures and applicable administrative controls, cognizant of in-process surveillance and maintenance activities, and aware of inoperable equipment status. The inspectors performed channel verifications and reviewed component status and safety-related parameters to verify conformance with TS. Shift changes were observed, verifying that system status continuity was maintained and that proper control room staffing existed. Access to the control room was controlled and operations personnel carried out their assigned duties in an effective manner. Control room demeanor and communications continued to be informal, yet effective.

Plant tours and perimeter walkdowns were conducted to verify equipment operability, assess the general condition of plant equipment, and to verify that radiological controls, fire protection controls, and physical protection controls were properly implemented.

Source Range Monitors

In preparation for fuel reloading, I & C determined on December 4, 1990, that both source range monitors (NI-31 and NI-32) were not operable and could not be repaired. Moisture apparently had intruded into the cables and/or connectors, and short circuited the detectors. A PNSC review of potential alternatives to monitor the core during fuel reloading resulted in a decision to replace both the NI-31 and NI-32 detectors. Replacement detectors were installed, tested, and placed in service on December 15, 1990. At the end of the report period, the licensee was in the process of replacing the source range and intermediate range monitor cables.

CCW Line Degradation

On December 13, 1990, during hydrostatic testing for modification M-1017, Eliminate RHR Pump Common Mode Failure, the CCW return line from the A RHR pump seal cooler ruptured. Subsequently, based upon a visual inspection, engineering concluded that portions of the supply and return lines into the RHR pit were so extensively damaged by external corrosion that successful hydrostatic test completion appeared improbable. Engineering recommended replacement of supply and return piping sections from both A and B RHR pump seal coolers. The pipe replacement was accomplished in accordance with WR/JO 90-ARIT1, 90-ARIW1, and 90-ARJK1. The piping was subsequently successfully hydrostatically tested on December 19, 1990, per SP-369, System Hydrostatic Pressure Testing of Component Cooling Water System, and returned to service.

The affected piping consisted of approximately 20 feet of 1 and 2-inch, schedule 40 carbon steel piping. Preliminary root cause analysis indicated that water, most likely rain, had over a period of years penetrated between the pipe and its thermal insulation, thereby wetting the pipe OD and causing the external corrosion. The piping degradation went undetected apparently due to the piping being insulated. The replacement piping was painted with an epoxy type paint to reduce the potential for external corrosion. The licensee has not determined what monitoring or inspections, if any, are necessary to detect future or additional external piping corrosion. This is an IFI: Review Steps To Detect And/Or Preclude Extensive External Corrosion Of Carbon Steel Piping, 90-30-01.

Inspection Report 89-09 discussed a RHR system common mode failure in which a leak in the RHR pit would not be isolable during the recirculation phase of an accident due to high radiation fields. This postulated scenario would eventually result in both RHR pump motors shorting out (i.e., loss of all ECCS capability). The report describes compensatory measures to isolate certain potential leak paths into the RHR pit by closing certain valves before entering the recirculation phase of an accident. The compensatory actions did not include isolation of the CCW lines to the RHR pump seal coolers. The pump vendor indicated that the RHR pump seals could operate indefinitely at the temperatures anticipated during the recirculation phase of an accident; however, it was considered prudent to have the seal coolers remain in service during an accident. This decision was based in part on the determination that leakage from these lines was a relatively small contributor to the estimated core melt frequency for the assumed event. If an external inspection had been performed of these lines at that time, it appears that the low probability of failure would not have been assumed. The inspectors discussed with management that future JCO evaluations should consider what measures, if any, need to be taken to establish confidence that equipment relied upon for acceptable continued operation is not degraded.

<u>1990 Radiological Goals Status</u>

The E & RC Manager provided the inspectors with the following actual end-of-year status of selected radiological goals:

	Actual	Goal
Exposure (Person-REM)	437	<450
Contamination Events	235	<300
Contaminated Area (sq. ft.)	5795	<2000
Radwaste Volume (cu. ft.)	2467	<4000

Prior to the outage (i.e., end of August 1990), the contaminated area YTD value was 1220 sq. ft.. During the outage, the contaminated area has typically varied between 5,000 and 6,000 sq. ft.. The licensee is decontaminating areas such that the amount of contaminated space will be reduced to levels similar to that existing prior to the outage. The radwaste volume shipped is the lowest amount since 1973, the year in which radwaste volume trending was initiated.

System Cleanliness

On January 3, 1991, the inspectors observed that CC-702A, the A CCW pump discharge check valve, had been left open without anyone in the area. The inspectors reported this condition to an operator so that appropriate measures could be taken to preclude foreign materials from entering the system. The inspectors visually verified that no foreign materials had entered into the valve body at that time.

SW System Outage Activities

During RO-13, extensive inspections, repairs, refurbishment/replacements, and modifications were performed on the SW system and its components. These activities were performed as a result of various requirements (i.e., GLs 89-13 and 90-05), commitments, and licensee initiatives. The inspection portion of the SW system efforts included visual and camera inspections of the 30", 24", 20", 18", and 16" diameter, cement-lined piping. This inspection included both the buried north and south SW supply headers which are discussed later in detail. Key SW check valves inspected include: the A,B,C, and D SW pump discharge check valves, SW-374, -376, -375, and -377, respectively; the north and south header check valves, SW-541 and -545, respectively; and the A and B SWBP discharge check valves, SW-561 and -560, respectively. These valves were not disassembled due to replacement part unavailability; however, each valve was inspected, cleaned, and mechanically stroked with the exception of SW-561, which was replaced on November 8, 1989.

With the exception of the buried SW supply headers, most of the cement-lined SW lines and joints inspected were relatively sound, with only localized cement liner spalling evident. These localized areas, as well as the header joints, were repaired with Speed Crete Blue Line, which is a commercially prepared portland cement mortar. The acceptability of this material was justified and approved by EE 90-100, Revision 0, Evaluation of a Commercial Prepared Portland Cement Mortar for Repair of Cement Lining of the RNP's Service Water Pipes. The repairs were performed under SP-968, Cement Lining Repairs Using "Speed Crete Blue Line". Additionally, a black "slime" was identified as covering the inside of the large majority of the SW piping inspected. This foreign substance is discussed in the following paragraph. In regard to the buried north and south SW supply headers, the following paragraphs give a brief description of the inspection/repairs that were performed on the subject piping.

The buried SW supply piping is a 31.375" OD by 0.188" nominal wall, cement-lined pipe divided into two headers approximately 900 feet long each. The piping was purchased and installed in 1968 under the AWWA specifications. Camera, visual, and UT inspections were performed inside the pipe. The initial camera inspections, as well as visual walkdowns, indicated the piping to be coated with a black "slime" with localized areas of concrete lining missing. The inspections also identified that the non-coated cross-sectional areas had experienced corrosion-induced pipe thinning. Degradation was observed primarily in the bell and spigot (mechanical slip-fit) joints with additional joints also exhibiting corrosion. The black "slime" was determined to be manganese dioxide hydroxide and iron dioxide hydroxide. Agitation and aeration of Lake Robinson water which contains high levels of tanic acid caused these chemicals to precipitate out of solution.

After the initial inspections revealed corrosion in the locations which were not cement-lined, the licensee attempted to quantify the degree of corrosion through interior UT examinations of selected north and south header joints. This UT indicated that there were not any areas with a minimum wall thickness less than the calculated required thickness. Based upon both the interior UT and the visual examinations, the bell and spigot joints in the north header were cleaned and covered with Speed Crete. Subsequently, it was determined that the interior UT data was invalid due to the UT probe being larger than the effective size of the corroded areas being measured (i.e., some pit depth was measured as wall thickness). Additional and more accurate UT was then performed on selected joints from the piping's exterior. Based on the initial visual determination that the south header was in worse shape and more susceptible to corrosion (i.e., piping not as well fit-up with larger joint gaps and contained more elbows), the additional examinations focused on the joints determined to be the 12 worst south header joints. Two "typical" (bell and spigot) joints in the south header, S-10 and S-42, were determined to require repair. All other "typical" joints were evaluated per calculations and formulas (calculation no. RNP-C/STRS-1114) per ASME Code Case N-480 and were determined to be acceptable.

The four atypical (non-bell and spigot) joints in the north header were repaired/replaced based on the corrosion severity on those joints. In addition to south header joints S-10 and S-42, weld areas on joints S-6, S-31, and a factory butt welded joint required repair. Joints S-10 and S-42 utilized a butt strap repair/replacement technique, where S-6, S-31, and the factory joint required weld repair. All repair/replacements were performed in accordance with the original pipe design, ASA B31.1-1955 Edition, Code for Pressure Piping, and AWWA Standard, ANSI/AWWA C206-88, Field Welding of Steel Water Pipe. Subsequent weld joint inspection was performed per AWWA C206-88, Section 5.8. All repaired/replaced joints were subsequently covered with Speed Crete. Upon repair/replacement completion, the system was hydrotested per ASME Section XI, IWA-5000, 1977 Edition, Summer 1978 Addenda. At the end of the report period, the inspectors had not reviewed the calculations, inspections, and hydrotest results; however, they were deemed acceptable by the licensee.

Also inspected during the outage were the smaller diameter SW lines, as well as the SW intake structure and traveling screens. The intake structure and screen inspections did not identify significant structural damage nor sediment/fouling buildup that could affect SW pump performance. Smaller diameter SW piping lines (i.e., MDAFW and SDAFW Lube Oil Coolers, ECCS Pump Room Coolers) were determined to have varying degrees of fouling. The normal manual cleaning and flushing method was supplemented by utilization of a foam plug or "pig". The procedure involved the forcing of the "pig" through the lines, thus swabbing the pipe walls and loosening the fouling material. The lines were subsequently flushed. Some small diameter SW lines were only manually cleaned and flushed.

During the outage, extensive refurbishment was performed on three SW pumps and three motors, as well as the SWBPs and motors. The refurbishment included, but was not limited to: shaft, impeller, and bearing replacement; tolerance and clearance checks; shop testing; and generation of pump specific head curves. The motor refurbishment (also vendor performed) included cleaning, tolerance checks, electrical testing, etc., as well as any necessary component repair/replacement. At the end of the report period, A, B, and D SW pumps and motors had been refurbished and installed with the original C pump and motor installed as well. The refurbished C motor (originally a spare) was expected to arrive on site by January 18, 1991. An additional refurbished (spare) pump was already on site. Upon delivery and outage schedule permitting, the refurbished pump and motor will be installed. Subsequent to this installation, the original C pump and motor will be refurbished, with the pump's internals being upgraded. The refurbished SWBP and motors have been reinstalled.

Prior to the outage, twenty-nine SW valves were scheduled to be replaced. The valves were scheduled for replacement due to design changes, lack of replacement parts, and in some cases due to degradation. Component availability resulted in twenty-two of these valves being replaced, as well as three others which were originally scheduled for repair. The following is a list of the replaced valves:

Valve	Description
SW-20	CCW Hx A Cooling Water Supply
SW-21	CCW Hx B Cooling Water Supply
SW-23	SW Return from Auxiliary Building
SW-142	TCV-1650 Inlet
SW-143	TCV-1650 Outlet
V6-33 A,B,C,D,E,F	SWBP Supply to HVH Units
V6-34 A,B,C,D	HVH Cooling Water Return Isolation
SW-24	South Header Supply to SWBP
SW-26	SWBP Suction Cross Connect
SW-27	SWBP Suction Cross Connect
SW-28	SWBP A Suction Valve
SW-29	SWBP B Suction Valve
SW-32	SW Pump A Discharge Valve
SW-33	SW Pump B Discharge Valve

SW-739	CCW Hx A Cooling Water Return
SW-740	CCW Hx B Cooling Water Return
SW-741	CCW Hx B and Auxiliary Building Return Isolation

The seven SW valves which were not replaced included: V6-12A and D, the South and North SW Supply Header Isolation valves, respectively; V6-12B, and C, the SW Pump Discharge Cross Connect valves; V6-16 A and B, the North and South SW Supply to Turbine Building, respectively; and V6-16C, the Turbine Building Cooling Water Isolation valve. The V6-12 valves were inspected and found to be in good condition (i.e., no repair or replacement was necessary). The V6-16 valves were inspected, cleaned, Belzona covered, and received new seats. Valves SW-739, -740, and -741 which were not originally scheduled for replacement were replaced due to significant degradation. Additionally, significant pipe erosion downstream of these latter valves was detected. The eroded pipe was replaced. Some erosion had been anticipated; however, the amount of degradation found was unexpected. The system engineer plans on initiating a PM Route to inspect this piping on a regular interval. This is an IFI: Establishment of PM Route To Inspect SW Piping, 90-30-02.

While the SW buried piping corrosion issue/resolution was very complex and time consuming, the communications and interfaces between Technical Support and NED were effective, with the Technical Support system engineer's coordination and oversight being particularly noteworthy.

Spent Fuel Shipments

On December 4, 1990, fourteen spent fuel assemblies were transported from the HBR site to the spent fuel storage facility at SHNPP in North Carolina. Future shipments are scheduled for 1991. The shipments will allow sufficient room in the spent fuel pool for a full core off-load.

No violations or deviations were identified.

3. Monthly Surveillance Observation (61726)

The inspectors observed certain safety-related surveillance activities on systems and components to ascertain that these activities were conducted in accordance with license requirements. For the surveillance test procedures listed below, the inspectors determined that precautions and LCOs were adhered to, the required administrative approvals and tagouts were obtained prior to test initiation, testing was accomplished by qualified personnel in accordance with an approved test procedure, test instrumentation was properly calibrated, and that the tests conformed to TS requirements. Upon test completion, the inspectors verified the recorded test data was complete, accurate, and met TS requirements; test discrepancies were properly documented and rectified; and that the systems were properly returned to service. Specifically, the inspectors witnessed/reviewed portions of the following test activities:

OST-401 (revision 25)	Emergency Diesels (Slow Speed Starts)
SP-1002	RHR Pump Flow Test

RHR Flow Test

On January 4, 1991, the inspectors observed performance of SP-1002, RHR Pump Flow Test. While attempting to take flow and pressure data with the A RHR pump operating in shutdown cooling, the flow rate appeared unstable or oscillatory in nature. The procedure was discontinued after two sets of data was taken. At the end of the report period the flow instability cause(s) had not been determined and a revised test procedure was being prepared utilizing another system configuration. The licensee plans to perform this test and resolve the issue prior to startup. The inspectors will review and document the resolution in IR 91-01.

No violations or deviations were identified.

4. Monthly Maintenance Observation (62703)

The inspectors observed safety-related maintenance activities on systems and components to ascertain that these activities were conducted in accordance with TS and approved procedures. The inspectors determined that these activities did not violate LCOs and that required redundant components were operable. The inspectors verified that required administrative, testing, radiological, and fire prevention controls were adhered to. In particular, the inspectors observed/reviewed the following maintenance activities:

90-ALYE1	Snubber 30 Bracket Repair
91-ARRSI	Adjustment of A EDG Turbocharge Exhaust Nozzle
90-AKGE1	Votes Testing of FW-V2-6A
90-AKGF1	Votes Testing of FW-V2-6B
91-AAQH1	MCC Contractor Contacts Inspection

B RHR Pump Impeller

On November 26, 1990, the inspectors witnessed the technical support inspection of the B RHR pump impeller. The impeller was considered to be in good condition; however there was an eroded area, less than 1 sq. cm., observed on one discharge vane. Repair of this area was deemed not to be currently necessary. At the end of this reporting period, the licensee had not determined if periodic inspections of the eroded area need to be conducted. This an IFI: Review Periodic Inspection Frequency Determination For B RHR Pump Impeller, 90-30-03.

A EDG Operating Temperatures

The A EDG, Fairbanks Morse model 38TD81/8, has historically operated fully loaded with the exhaust temperature approximately 100 degrees centigrade higher than that measured on the B EDG. Individual cylinder exhaust temperatures have been 50 to 75 degrees centigrade hotter on A EDG than these experienced on the corresponding B EDG cylinders. The A EDG turbocharger air inlet check valve has not operated in a manner similar to the B EDG valve. Normal valve operation is as follows: At less than 80 to 90 percent of full load (2500 KW) the valve is fully closed. This allows the inlet air to be diverted through the scavenger air blower prior to being routed under the valve and into the turbochargers. As the load is increased, an increasing volume of air is drawn into the engine and exhausted through the turbocharger exhaust turbine blades. The increasing flow increases the turbocharger speed (i.e., the inlet pressure decreases at the turbocharger suction and below the air inlet check valve). The differential pressure across the valve will result in the valve modulating open as load increases. Opening of the air inlet check valve allows air to flow directly to the turbocharger. The air flow, being increased above the scavenger air blower's capacity, allows the cylinders to operate at a lower temperature than that experienced with only the scavenger air blower air flow. The B EDG valve works in this manner; however, the A EDG air inlet check valve remains closed and/or open less than desired as load is increased to full load. The ability to operate the A EDG at full load with operating temperatures similar to B EDG has been demonstrated by manual valve operation.

Actions taken to date have not corrected the A EDG's high temperature condition. These actions included: replacement of both turbochargers, adjustment of the turbocharger exhaust nozzles to increase turbocharger rpm, and inlet check valve replacement. These actions have been developed in conjunction with, and monitored by, a Colt Industries technical representative. On January 8, 1990, air pressure data was recorded with the A and B EDG engines operating at various loads. This information along with previously submitted data was being analyzed by the vendor for other possible corrective actions. Correction of this higher than normal temperature condition is considered to be desirable (i.e., would improve reliability, but is not required for the A EDG to perform its safety function).

The inspectors have discussed the above problems and corrective actions with both the engineering staff and the vendor representative and observed various associated corrective maintenance as it was performed.

RHR-753B Degradation

During the performance of OST-251, RHR Component Test, on December 24, 1990, valve RHR-753B, the B RHR pump discharge check valve, did not close. Inspection of the valve internals revealed that the clapper arm was worn and the disc travel stop was deformed. The valve is a 10-inch Aloyco swing disc check valve. Apparently, the disc stem had become misaligned due to the worn arm and had stuck on the gouged stop. According to the vendor, this is a known failure mode for this valve. The stop was weld repaired in accordance with WR/JO 90-ARZT5, the valve was reassembled, and proper operation was verified by the successful completion of OST-251. The worn clapper arm will be replaced when a replacement part is received in mid-January.

This valve had been inspected on November 24, 1990, per PM-300, Aloyco Swing Check Valve Inspection, revision 0. Though PM-300, revisions 0 and 1, steps 7.2.1 and 7.3.10.1 required inspection and documentation of the general condition of the valve body, no specific steps were provided to address the travel stop. Though deformation of the travel stop was observed on November 24, 1990, it was not documented on Attachment 8.4 of PM-300. Failure to specifically require the condition of the stop to be documented so that degradation can be detected is considered a VIO: Procedure PM-300 Was Inadequate In That Condition of The Aloyco Check Valve Travel Stop Was Not specifically Required To Be Evaluated and Documented, 90-30-04.

The inspectors are concerned that the maintenance procedure upgrade program failed to incorporate specific steps in the inspection procedure to address a known failure mode.

One violation was identified.

5. Refueling Activities (60710)

Movement of fuel into the reactor vessel was initiated on December 25 and completed on December 29, 1990. The inspectors observed 12 fuel assemblies being loaded on December 28. The inspectors verified that activities were being conducted in accordance with FMP-019, Fuel and Insert Shuffle and GP-010, Refueling. During refueling activities, the inspectors verified that the requirements of TS 3.8.1 c, 3.8.1.d, 3.8.1.e, 3.8.1.g, 3.8.1.h, and 3.8.2.d were being met. On December 27 the inspectors observed that refueling activities were suspended in accordance with TS 3.8.2.d when the relative humidity of the air processed by the refueling filter systems approached 70 percent. Fuel movement resumed when the relative humidity decreased to less than 70 percent. Later that night and the next day, fuel movement had to be suspended on two additional occasions due to relative humidity restrictions. The condition was caused by a combination of faulty duct heaters and rain and fog in the area.

Inspection Report 90-22 documented that cleanliness controls in the reactor cavity area at the start of control rod unlatching was poor. The inspectors observed that housekeeping was being maintained at an acceptable level during fuel reloading.

6. Action on Previous Inspection Findings (92700, 92701, 92702, 71707)

Upper Internals Repair

During the September 1990 reactor vessel upper internals inspection, the licensee observed crack indications in 38 control rod guide tube support pins (split pins) and 13 guide tube removable inserts with less than the necessary number of flexures. See IR 90-22 and 90-24 for additional description of these problems.

By December 12, 1990, the licensee had completed replacement of split pins on all 53 guide tubes with a redesigned split pin. The replacement split pins received a higher temperature heat treatment and have a larger shank to collar radius than the original supplied split pins. The heat treatment makes the material less susceptible to IGSCC and the radius increase reduces the stresses at a location where IGSCC had occurred in the previous designed type of split pins. By December 12, 1990, flexureless inserts had also been installed on the guide tubes such that all 45 guide tubes which had removable inserts earlier now have flexureless inserts. Eight guide tubes of the total 53 guide tubes did not have flexures. These eight guides tubes were used previously with the no longer installed partial length control rods. Based upon the repair/replacement activities, the split pin and flexure failure issues have been satisfactorily addressed.

S/G Girth Weld 5 ID Indications

Inspection Report 90-24 documented that preliminary in-process external UT examination of A S/G weld 5 (upper girth weld) resulted in detection of low amplitude ultrasonic reflectors at the vessel ID which ran circumferentially in the base metal adjacent to the wall edge. Subsequently, indications have been found in the same general area of C S/G. Ultrasonic examinations had previously recorded isolated indications on the B S/G upper girth weld. The B S/G indications were not considered to be indicative of cracks. After reviewing available information, the licensee decided to perform internal ID magnetic particle examination of the A S/G weld 5. The A S/G was selected because its external UT examination had been completed (i.e., C S/G was still being examined) and A S/G was more readily accessible than C S/G due to outage activities in and around the S/Gs. Visual examination of the A S/G weld from the inside revealed no indication of cracks. The visual inspection also revealed that the weld on the inside was much wider, 3 to 4 inches in width, than shown on the drawing. Thus, the UT indications were all in the weld area, not in the base metal as originally thought. Ten linear feet of the weld, encompassing the worst UT indications, was selected for fluorescent MT. This confirmed that surface indications were present in the weld, and not in the base metal. Two indications were surface prepared before the MT. These indications were found to be associated with weld porosity. Preliminary analysis of the A and C S/G UT results by Structural Integrity

Associates indicates that it is acceptable to operate at least one cycle. The UT and MT results were discussed with Region II and NRR personnel via a conference call on December 14, 1990. The NRC has tentatively concurred with the licensee's approach (i.e., it is acceptable to operate one cycle without removing the indications). The licensee has agreed to submit to NRR for further review the UT and MT examination results and the associated engineering analysis prior to startup. In addition, the licensee indicated a willingness to perform external UT examinations of the affected S/G areas should a forced outage of sufficient duration put the unit in cold shutdown after mid-cycle. Such an examination would determine if the character of the existing indications had changed. The licensee currently plans to re-examine these indications during the next refueling outage, scheduled for March 1992. On December 18, 1990, the inspectors visually inspected an accessible portion of the A S/G welds from the secondary side. Comparison of the observed conditions with those depicted in pictures from another site that had pitting which resulted in rapidly propagating cracks, showed that such pitting did not exist in the area viewed. These pictures were also viewed by the cognizant engineer who had looked at the entire A S/G weld 5 area. The engineer also indicated that pitting as shown in the other site's pictures did not occur in the A S/G.

On December 18, 1990, while removing work platforms from inside A S/G, an internal ladder rung broke at its attachment weld and fell into the annulus area. Subsequent underwater TV camera inspection located the broken rung and the part was retrieved. Magnetic particle testing of the other ladder rungs' attachment welds revealed no other defects.

The communications and interfaces among the groups (NED, HEEC and Technical Support) involved in the resolution of the S/G indications were effective. The support provided to the site by the offsite organizations was especially noteworthy.

(Closed) VIO 89-18-01, 10 CFR 50 Appendix B Criterion XVI Failure To Promptly Identify And Correct Conditions Associated With the AFW System - Potential Escalated. Inspection Report 89-18 transmittal letter identified that the subject item was under consideration for escalated enforcement action and accordingly no NOV was being issued at that time. On November 15, 1989, the NOV was issued with a proposed imposition of civil penalty. Inspection of this item is being conducted under item number 89-11-01. Thus, for administrative purposes, violation 89-18-01 is considered closed.

No violations or deviations were identified.

7. Exit Interview (30703)

The inspection scope and findings were summarized on January 15, 1991, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings listed below and in the summary. Dissenting comments were not received from the licensee. Proprietary information is not contained in this report.

Item Number	Description/Reference Paragraph
90-30-01	IFI - Review Steps To Detect And/Or Preclude Extensive External Corrosion Of Carbon Steel Piping, paragraph 2.
90-30-02	IFI - Establishment Of PM Route To Inspect SW Piping, paragraph 2.
90-30-03	IFI - Review Periodic Inspection Frequency Determination For B RHR Pump Impeller, paragraph 4.
90-30-04	VIO - Procedure PM-300 Was Inadequate In That Condition Of The Aloyco Check Valve Travel Stop Was Not Specifically Required To Be Evaluated And Documented, paragraph 4.

8. List of Acronyms and Initialisms

AFW	Auxiliary Feedwater
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
AWWA	American Water Works Association
CC	Component Cooling
CCW	Component Cooling Water
CFR	Code of Federal Regulations
cu. ft.	Cubic Feet
e.g.	For Example
ECCS	Emergency Core Cooling System
E & RC	Environmental and Radiation Control
EDG	Emergency Diesel Generator
EE	Engineering Evaluation
EQ	Environmental Qualification
FMP	Fuel Management Procedure
GL	Generic Letter
GP	General Procedure
HEEC	Harris Energy and Environmental Center
HVH	Heating, Ventilation Handling

I&C	Instrumentation & Control
ID	Inside Diameter
IFI	Inspector Followup Item
IGSCC	Intergranular Stress Corrosion Cracking
IR	Inspection Report
JCO	Justification For Continued Operation
KW	Kilowatt
LCO	Limiting Condition for Operation
MCC	Motor Control Center
MDAFW	Motor Driven Auxiliary Feed Water
MT	Magnetic Particle Testing
NED	Nuclear Engineering Department
NI	Nuclear Instrumentation
NOV	Notice of Violation
NRR	Nuclear Reactor Regulation
OD	Outside Diameter
OST	Operations Surveillance Test
PM	Preventative Maintenance
PNSC	Plant Nuclear Safety Committee
REM	Roentgen Equivalent Man
RHR	Residual Heat Removal
RNP	Robinson Nuclear Project
rpm	Revolutions Per Minute
RO	Refueling Outage
RW	Radwaste
SDAFW	System Driven Auxiliary Feedwater
S/G	Steam Generator
SHNPP	Shearon Harris Nuclear Power Plant
SP	Special Procedure
Sq. Ft.	Square Feet
Sq. Cm.	Square Centimeters
SWBP	Service Water Booster Pump
SW	Service Water
TS	Technical Specification
TSC	Technical Support Center
TV	Television
URI	Unresolved Item
UT	Ultrasonic Test
VIO	Violation
WR/JO	Work Request/Job Order
YTD	Year To Date