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

Report No.: 50-261/85-30

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: September 16-20, 1985

Inspector: W J Ross 10-2-85
W. J. Ross Date Signed

Approved by: J J Blake 10-2-85
J. J. Blake, Section Chief Date Signed
Engineering Branch
Division of Reactor Safety

SUMMARY

Scope: This routine, unannounced inspection entailed 37 inspector-hours on site in the areas of plant chemistry and inservice inspection of pumps and valves.

Results: No violations or deviations were identified.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

G. P. Beatty, Manager, H. B. Robinson Nuclear Project
*R. E. Morgan, General Manager
*J. M. Curley, Manager, Technical Support
*R. N. Smith, Manager, Environmental and Radiation Control (E&RC)
*D. C. Shadler, Director, Regulatory Compliance
*C. L. Wright, Senior Specialist, Regulatory Compliance
*J. A. Eaddy, Chemistry Supervisor, E&RC
W. Christensen, Chemistry Foreman, E&RC
R. Hitch, Chemistry Specialist
J. Murray, Water Treatment Supervisor, Operations
R. Chambers, Supervisor, Performance Engineering
W. Farmer, Performance Engineer

Other licensee employees contacted included chemistry, technicians and water treatment operators.

NRC Resident Inspectors

H. Krug
*H. C. Whitcomb

*Attended exit interview

2. Exit Interview

The inspection scope and findings were summarized on September 20, 1985, with those persons indicated in paragraph 1 above. No dissenting comments were received from the licensee.

The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspector during this inspection.

3. Licensee Action on Previous Enforcement Matters

This subject was not addressed in the inspection.

4. Unresolved Items

Unresolved items were not identified during the inspection.

5. Plant Chemistry (79501 and 79502)

As a result of its continuing concern for steam generator tube integrity, the NRC staff has recently issued recommended actions and review guidelines that are directed toward the resolution of unresolved safety issues regarding this subject (see Generic Letter 85-02 dated April 17, 1985.) One recommended action is as follows:

> "Licensees and applicants should have a secondary water chemistry program (SWCP) to minimize steam generator tube degradation. The specific plant program should incorporate the secondary water chemistry guidelines in the Steam Generator Owners Group (SGOG) and Electric Power Research Institute (EPRI) Special Report EPRI-NP-2704, "PWR Secondary Water Chemistry Guidelines," October 1982, and should address measures taken to minimize steam generator corrosion, including materials selection, chemistry limits, and control methods. In addition, the specific plant procedures should include progressively more stringent corrective actions for out-of-specification water chemistry conditions. These corrective actions should include power reductions and shutdowns, as appropriate, when excessively corrosive conditions exist. Specific functional individuals should be identified as having the responsibility/authority to interpret plant water chemistry information and initiate appropriate plant actions to adjust chemistry, as necessary.
>
> The reference guidelines were prepared by the Steam Generator Owners Group Water Chemistry Guidelines Committee and represented a consensus opinion of a significant portions of the industry for state-of-the-art secondary water chemistry control."
>
> Reference
>
> Section 2.5 of NUREG-0844

In parallel action, the NRC Office of Inspection and Enforcement has developed two new Inspection Procedures to verify that the design of a plant provides conditions that ensure long term integrity of the reactor coolant pressure boundary and to determine a licensee's capability to control the chemical quality of plant process water in order to minimize corrosion and occupational radiation exposure.

The objectives of these new procedures were partially fulfilled during previous inspections (See Inspection Reports 50-261/83-34 and 50-261/84-49 dated December 20, 1983 and January 14, 1985). This follow-up inspection consisted of an evaluation of the licensee's operating experience since the plant returned to power after major modifications had been made to the secondary water system and AVT water chemistry control had been initiated.

a. Plant Design and Operation

The major changes and additions to the secondary water system were addressed previously in Inspection Report 84-49 (i.e., main condenser, makeup water plant, condensate cleanup system, AVT chemistry system, feedwater heaters and moisture separator reheaters, and steam generator tube bundles.) As also discussed in this previous Inspection Report, startup with these modifications was delayed (until February 1985) because of previously unidentified deterioration of Service Water pipes caused by micro-biologically-induced stress corrosion.

At the time of this inspection the plant had completed approximately two-thirds of the current fuel cycle; i.e., 200 of 311 effective full power days. During this period the plant had experienced ten power excursions (trips) to zero percent power and an equal number of power reductions of 100 MWe or greater. (One reactor trip occurred during this inspection.) None of these power losses was attributed to a chemistry or corrosion-related problem; however, the plant was twice placed in Action Level Two condition when steam generator water chemistry parameters (chloride and cation conductivity) increased during power reduction as the result of hideout return. In addition, the plant was placed in Action Level One condition several times when high levels of dissolved oxygen were detected in the condensate. An oxygen transient also occurred during this inspection.

The concentration of dissolved oxygen in the condensate has varied from 6-12 ppb since the plant started up. The inspector noted that air inleakage into the condensers had usually been only 3 to 4 standard cubic feet per minute (a range that compares very favorably with other nuclear power plants) although inleakage of more than 10 SCFM had been reported during four brief periods. The licensee has not determined why the condensate oxygen continues to be high, and is planning to inspect for very small leaks in the condenser during the next refueling outage (January - February 1986).

The inspector observed that the total concentration of impurities in the condensate had remained very low (e.g., cation conductivity of 0.07 - 0.08 umho/cm), thus indicating that there had been very little ingress of impurities through inleakage of condenser cooling water or through contaminants in the condensate makeup water. Likewise, through the use of the deep-bed demineralizer system, that had been installed as part of the plant modification, the low and high-pressure pipes in the secondary cycle were being effectively cleaned of solid and soluble material during each startup from zero power. These demineralizers also are being used continually to polish the condensate during plant operation. As the result, the feedwater has also been of very high quality; e.g., its cation conductivity has continuously been decreasing from 0.1 to 0.06 umho/cm (essentially pure water) while dissolved oxygen has remained at 1 to 3 ppb.

The purity of the feedwater has been subsequently translated into high quality steam generator water. The cation conductivity of the steam generator blowdown has decreased from 0.6 to 0.25 umho/cm during this fuel cycle, while other key chemistry control parameters (sodium, chloride, sulfate) remain significantly lower ($\sim$ 5 ppb) than the limits (20 ppb) recommended by the Steam Generator Owners Group (SGOG) to prevent the formation of localized corrosive environments in the steam generator. (The inspector observed that the licensee is still detecting phosphate in the steam generator blowdown, although those portions of the steam generators that were not replaced had been cleaned to remove residual phosphate salts prior to initiation of all volatile chemistry (AVT) control.

The inspector reviewed the licensee's experience with the new condensate cleanup system. Although these deep-bed demineralizers are used to remove soluble and insoluble impurities from the condensate, they become loaded predominantly with the ammonia that is added to control pH. Consequently, they must be regenerated approximately every 11 days. The inspector was informed that cross contamination of the anion and cation resins with regenerant chemicals (sodium hydroxide and sulfuric acid) was being effectively eliminated through the use of a layer of inert resin beads that keeps the anion and cation resins separated. Consequently, 'throw' of sodium and sulfate from freshly regenerated resin beds into the feedwater has been prevented.

The current fuel cycle is the first time that the licensee has controlled secondary water chemistry with all-volatile chemicals (AVT chemistry); i.e., hydrazine and ammonia. These chemicals are normally added at the condensate polisher outlet, although they also can be injected into the low-pressure turbine crossover line when additional control of oxygen or pH in the hotwells and/or condensate lines is needed. (These chemicals are also added to the Condensate Storage Tank and to the suction of the Auxiliary Feedwater Pumps.) The SGOG recommends that the pH of the feedwater in PWRs (that do not have copper-alloy components) be maintained at 9.3 to 9.6 and the pH of the water in the steam generator be kept at 9.0 to 9.5 to minimize oxidation of carbon steel pipes and steam generator structural components. The licensee has decreased these limits to 8.8 - 9.6 in the feedwater and 8.5 to 9.5 in the steam generator to reduce the rate with which the condensate polishers are being loaded with ammonia. The inspector observed that during the current fuel cycle the pH of both condensate and feedwater had been 9.0 $\pm$ 0.3 and the pH of the steam generator water had been in the range of 8.5 to 9.0.

Although the licensee is maintaining pH control lower than that considered to be optimum for corrosion control of carbon steel pipe, this action is not out of line with other nuclear power plants, especially those where deep bed demineralizers are used. (Where

condensate polishers are now being bypassed licensee's are increasing the pH of the secondary cycle to ∿ 9.5 to maximize protection against iron oxidation. The licensee is considering this type of action if and when condensate polishing is not needed.)

The new steam generator blowdown system is capable of removing 300 gpm of water from each steam generator to provide cleanup of the steam generators; however, since blowdown water and thermal energy are currently not being recovered blowdown is normally being maintained at approximately 45 gpm per steam generator. The licensee believes that this level of blowdown will minimize deposition of iron oxide sludge on the steam generator tubes and tube sheets and, therefore, will prevent potential corrosive environments from being formed. In an effort to maintain the concentration of corrosive ions in the steam generator to a minimum, operating procedures for plant shutdown now include 'chemical holds' during cooldown to permit removal, through blowdown, of ions that may have been solubilized as 'hideout return'.

The inspector was informed that the steam generators will be sludge lanced during the next refueling outage to ensure that they remain as free of solids as possible. The inspector also observed that the startup schedule for the next refueling outage requires that the secondary water system be closed up so that the cyclic cleanup of the low-pressure pipes (condensate-feedwater) can be initiated two weeks before heatup begins in order to maximize removal of solids that might be transferred later to the steam generators.

Summary

An audit of quality of the water that has been maintained in the plant's secondary water system shows that ingress of ionic and solid contaminants has been effectively prevented during this fuel cycle. Constant observation of relatively high levels of dissolved oxygen in the condensate indicates either the presence of a very small leak in the condenser or erroneous instrument readings. The licensee plans to thoroughly inspect the condenser during the next refueling outage to see if an air leak does exist.

b. Secondary Water Chemistry Control

The inspector evaluated the licensee's chemistry control and monitoring program and the manner in which it had been implemented during this fuel cycle. This evaluation was based on the following: discussions with cognizant Chemistry and Water Treatment personnel; review of the latest revisions of procedures CP-001 Chemistry Monitoring Program and CP-005 Secondary Chemistry Action Program; observation of chemistry technicians and water treatment operators during their routine work; and monitoring the inline instrument panels in the Secondary Chemistry Sample Room and the Water Treatment Control room.

It is the inspector's opinion that the licensee made the conversion from phosphate - controlled to AVT-controlled secondary chemistry very efficiently. The chemistry staff is well trained in the SGOG criteria for control and diagnostic chemistry and in the use of inline instrumentation and grab samples to maintain the surveillance required to prevent the formation of corrosive conditions in the steam generators. The licensee is very well equipped with the facilities and analytical instrumentation needed for trace analyses and for handling radioactive samples. The inspector was favorably impressed by the condition of the laboratories and the operability and maintenance of inline monitors in both the Secondary Sample Room and the Water Treatment Control room. All key parameters for controlling the chemistry of condensate, feedwater, steam generator water, and main steam are monitored on these boards and the monitors are equipped with alarms. Consequently, abnormal chemistry conditions can be identified quickly and corrective action taken in the time frames recommended by SGOG guidelines to ensure protection of the steam generators.

As mentioned earlier in this report, the inspector observed the actions taken by the licensee to control secondary water chemistry after a reactor trip and after a rapid increase in the dissolved oxygen content of the condensate. In both cases corrective and preventive actions were taken consistent with SGOG recommendations to minimize damage to the steam generators. The licensee also used advantageously the new inline instrumentation and displays to monitor and trend changes in the secondary water chemistry that resulted from these two events.

On the basis of these observations, the inspector believes that the licensee is meeting the intent and goal of the recommended action in Generic Letter 85-02, related to implementation of a secondary water chemistry program.

The inspector also reviewed the licensee's control of the primary (reactor) coolant during this fuel cycle. An audit of data acquired to date showed that all Technical Specifications were being implemented properly and no control problems had been encountered.

During the review and inspection of the licensee's activities related to plant chemistry no violations or deviations were identified.

6. Inservice Testing of Pumps and Valves (61726)

The licensee's proposed program to test safety related pumps and valves in conformance with Section XI of the ASME Code is under review by the NRC staff. This review also involves an evaluation of the licensee's requests for relief from specific requirements of the ASME Code. During this inspection several relief requests were discussed and the inspector restated the NRC staff's position on each requirement.

The inspector also audited the licensee's Pumps and Valve Summary List and reviewed the results of tests that had been performed per Section XI of the ASME Code. These lists were considered to meet the intent of the code and to provide indications of changes in pump parameters and valve stroke times. The inspector identified the apparent degradation of Discharge Service Water Valves V6-33A, B, C, D, E and F as the result of stroke-time measurements that had been taken a few days earlier. These suspect valves were retested and the previous data were established to have been erroneous. It is the inspector's position that the Summary Lists should be used by Performance Engineering personnel to trend the pump and valve test results so that timely corrective action will be taken if true degradation is identified.