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

Report Nos.: 50-280/85-23 and 50-281/85-23

Licensee: Virginia Electric and Power Company
Richmond, VA 23261

Docket Nos.: 50-280 and 50-281 License Nos.: DPR-32 and DPR-37

Facility Name: Surry 1 and 2

Inspection Conducted: July 8 - 12, 1985

Inspector: W J Ross 7/26/85
W. J. Ross Date Signed

Approved by: 7/31/85
J. J. Blake, Section Chief Date Signed
Engineering Branch
Division of Reactor Safety

SUMMARY

Scope: This routine, unannounced inspection entailed 40 inspector-hours on site in the areas of plant chemistry and inservice testing of pumps and valves.

Results: No violations or deviations were identified.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*R. F. Saunders, Station Manager
*H. L. Miller, Assistant Station Manager
*E. S. Grecheck, Superintendent, Technical Services
J. W. Ogren, Corporate Director Operations and Maintenance Support
*W. A. Thornton, Corporate Supervisor System Chemistry
W. Hagan, Supervisor Water Management
L. G. Miller, Assistant Supervisor Chemisty
R. Blount, Supervisor, Inservice Inspection, Engineering

Other licensee employees contacted included chemistry, and technicians.

NRC Resident Inspectors

D. J. Burke
*M. Davis

*Attended exit interview

2. Exit Interview

The inspection scope and findings were summarized on July 12, 1985, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection findings listed below. No dissenting comments were received from the licensee.

(Closed) Inspector Followup Item 50-280, 281/84-16-01 Evaluation of Secondary Water Chemistry Program (Section 5.d).

(Closed) Inspector Followup Item 50-280, 281/84-16-02 Leakage of Primary Water Into the Component Cooling Water System (Section 5.d).

The licensee did not identify as proprietary any of the material 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 this 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 Generators 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 portion of the industry for state-of-the-art secondary water chemistry control."
>
> Reference
>
> Section 2.5 of NUREG-0844

In a 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 met during a previous inspection of the two Surry units, (see Inspection Report 84-16 dated June 6, 1984). The results of that inspection indicated that the capability to prevent ingress of corrosive contaminants into the three steam generators of each unit had been significantly improved through design modifications made in the secondary water cycle that were implemented when the original steam generators were being replaced in 1979-1980. The licensee was also in the process of revising the procedures and directives of the Surry secondary water chemistry program to incorporate the SGOG guidelines. This followup

inspection consisted of a reassessment of the licensee's activities in these two areas and a review of problems that were attributed to water chemistry during the past year.

a. Plant Design and Operation

At the time of this inspection, Unit 1 was operating at full power and Unit 2 was restarting after a refueling outage. During the refueling outages for both units during the past year the licensee continued to make major changes in the secondary water cycle to improve the protection of the steam generator from corrosion and tube failure. These changes and the status of the major components of the secondary water cycle are summarized as follows:

(1) Main Condensers

An audit of analyses made on condensate water while the units were at power during March-July 1985 indicated that water leakage through the retubed condensers was minimal. (Instrumentation for monitoring inleakage of condenser cooling water from the James River through continuous determination of sodium in each water box has not yet been installed.) Condensate chemistry parameters were within SGOG/EPRI guidelines and approximated the purity of demineralized water.

The inspector was informed that three percent of the titanium condenser tubes were eddy-current tested during the last refueling outages. As discussed in Inspection Report 84-16 some of these tubes have been damaged by mechanical wear, but no tube failure from corrosion has been observed.

Air leakage into the hotwells has been encountered, especially when the units are at low power level. The licensee continues to rely on a contractor to identify the sources of air inleakage and is attempting to maintain inleakage of less than 5 SCFM to protect the low-pressure turbines from corrosion as well as to minimize the dissolved oxygen content of the condensate.

(2) Condensate Makeup Water System

The licensee provides a supply of high quality water for primary and secondary coolants and other demands by purification of water taken from deep wells on site and from the James River. The water treatment process consists of flash evaporation of the raw water followed by demineralization of the distillate. Although the flash evaporators were retubed recently, the desired efficiency has not been achieved. Consequently, approximately 50 percent of the purified water is currently being produced by a mobile water treatment plant that has been contracted for until the plants systems can be made fully effective.

(3) Condensate Polishers

During the previous inspection, the inspector observed that through the use of full-flow deep-bed demineralizers the quality of the feedwater was being maintained at a high level. An audit of recent operational data indicated that normally this quality still remains very good. However, two problems have been encountered during the past year. Polishers bed 2B in Unit 2 has a weld crack that allows water to leak into the lower plenum of the tank, and this bed has been out of service since the end of the last fuel cycle. Consequently, now when a bed is generated there is no replacement bed available and, consequently, part of the condensate flow is not polished. This shortcoming has been especially troublesome during startup cleanup of the condensate when cleanup of hotwell water is needed. The licensee considers this to be maintenance deficiency. Also, early break-through of sodium has been encountered frequently because of insufficient rinsing of aged resin during the regeneration phase. During this inspection period, three demineralized beds were being replaced with new resin in an effort to eliminate this problem.

There is evidence, in hideout return studies, that sulfate ions are continually being 'thrown' from the polishers beds. This is a generic problems that is caused by cross contamination of anion and cation resins when they are regenerated with sulfuric acid and sodium hydroxide. The licensee is testing two additional types of resins to determine if better physical separation can be achieved. Also the use of inert resin to separate the cation and anion beds is still being considered. The licensee informed the inspector that consideration is also being given to installing a Graver CONESEP external regeneration system for the same purpose. In the CONESEP process the lower (heavier) cation resin beads are removed from the bottom of a conical shape tank until a monitor indicates contamination by the less dense anion resin beads.

The licensee informed the inspector that although its goal is to ultimately achieve such a clean secondary system that polishing will not be needed, there are no plans to bypass the demineralizers to eliminate throw of sulfate. Instead, the polishers will continue to be used as protection against a sudden loss of integrity of the condenser and inleakage of the brackish James River water that is used for condenser cooling.

(4) Feedwater System

During the past year, the licensee has initiated two positive actions to minimize the transport of corrosive soluble and solid contaminants to the steam generator. As part of the plant's operating procedure for restarting a unit from cold shutdown, specified chemistry limits must be met before power level may be increased above five percent and, subsequently, above 30 percent.

These 'chemistry holds' enables the water in the low-pressure (condensate/feedwater) lines, and, subsequently, in the high pressure (steam and condensate drain) lines, to be cycled back through the hotwell and condensate polishers until the specified purity is achieved.

Even these 'holds' failed to prevent contamination of the steam generator water during the startup of Unit 2. A significant increase in cation conductivity and chloride occurred while this unit was at ~60 percent power and was thought to have been caused by transport of soluble chloride from a section of pipe downstream of the heater drain pump when drain water was initially pumped forward to the feedwater pumps. The contaminated section of pipe had been installed during the refueling outage and had not been previously flushed during the startup cleanup. Although this incident was unique and probably will never reoccur, it emphasizes the need to monitor the water in the drain tank before it is pumped forward during startup.

In a separate action to minimize buildup of sludge in steam generators, the licensee has begun to replace all copper-containing alloys in the secondary water system. During the most recent refueling outages the moisture separator reheaters were replaced with stainless steel tubes. Similar replacement of the tubes in the feedwater heaters is scheduled to begin during the next refueling outages. By this means the licensee hopes to eliminate stress corrosion of steam generator components through processes that have been attributed to plating of copper or the presence of copper oxide in sludge that is deposited on the surfaces of steam generator tubes, tube sheets, and tube support plates.

(5) Steam Generators

The steam generators in both units were sludge-lanced during the most recent refueling outages. The results indicated that as the result of continual use of condensate polishers and steam generators blowdown, the amount of solids had been kept to very low level; i.e., a total of 62 pounds of sludge was removed from Unit 1 and 184 pounds from Unit 2. (Only 2.5 pounds were removed from steam generator 1B). The licensee believes that the sludge lancing technique was efficient and that these small quantities of sludge represent the true condition of the steam generators.

Most of the sludge was identified as oxides of iron, copper, nickel and minor metals and to represent oxidation products of the principal constituents of the carbon-steel pipe and copper-alloy tubes that are used throughout the secondary water cycle. The sludge from Unit 1 also contained several hundred parts-per-million of phosphate. Although the Surry units originally controlled secondary chemistry with phosphates, the licensee

cannot explain the presence of phosphate in the new steam generators. There was also small amounts of "non-metallic beads" that apparently consisted of carbonaceous material of unknown origin.

During the last refueling outage for Unit 2, the licensee repaired (by grinding) cracks that had been observed in the steam generators' transition-zone upper-girth welds. These welds were part of the original steam generators, and the cracks have been attributed to chemical pitting and to stress corrosion cracking prior to the replacement of the lower sections of the steam generators in 1979. The inspector was informed that in the period before the steam generators were replaced, the steam generator water frequency contained 25 ppb or more of dissolved oxygen and 300-400 ppm of chloride. There is further evidence that these welds cracks may have continued to propagate (through static stress or fatigue) even after chemistry control was improved.

In an effort to prevent similar residual buildup of corrosive ions in the steam generators the licensee continually blows down the steam generators during plant operation. In addition, plant operating procedures now include a 12-hour 'chemistry hold' when the temperature of the steam generator water drops to 350°F during a unit shutdown. During this 'hold' blowdown is continued in order to remove contaminants that are solubilized as 'hideout return' as the temperature decreases. The inspector observed that at the end of these 'holds' the concentration of sulfate in the blowdown still remained as high as 800 ppb. Consequently, even longer 'holds' would have been beneficial for cleansing the steam generators of this corrosive species.

(6) Main Steam System and Turbines

In an effort to eliminate any environment for further stress corrosion cracking in low-pressure turbine disks, the licensee has installed new rotors in all of the low-pressure turbines at the Surry station. The disks on the new rotors were designed to have less stress levels than before and, thus, be more resistant to stress corrosion that was theorized to have been initiated by condensation of steam and precipitation of trace amounts of corrosive salts and oxides. As will be discussed later, the licensee's capability to monitor the purity of the main steam has also been improved.

(7) Summary:

The inspector concluded that the licensee is continuing to take positive steps to make the design of the secondary water system conducive to the elimination of corrosive environments, especially in the steam generators. However, very little progress had been made during the past year in resolving problems associated the

production of condensate makeup water. The units operated by this licensee are unique in Region II in their use of flash evaporators to obtain high purity water. Most of the problems associated with the condensate cleanup system during the past year were attributed to delays in repairing one polisher vessel in Unit 2 and to the use of aged resins with degraded ion-exchange characteristics. The licensee is pursuing several avenues to eliminate the 'throw' of sulfate and to maintain the concentration of all key chemistry parameters in the steam generator to less than 20 ppb.

b. Scope and Adequacy of the Licensee's Water Chemistry Program

Since the inspector's previous inspection (May 1984) the licensee has completed the revision of administrative and chemistry procedures so that the Surry secondary water chemistry program is now consistent with the recommendations of the SGOG/EPRI guidelines. The inspector reviewed the following key procedures (Periodic Tests) that now incorporate specified limits or acceptance criteria for key control parameters as well as the action that must be taken by members of the Chemistry Section if a limit is exceeded. The few discrepancies between the requirements of these procedures and the recommendations of the SGOG/EPRI guidelines were explained satisfactorily by the licensee.

1-PT-38.38	Chemistry Sampling-Steam Generator Secondary Wet Layout (Unit 1)
1-PT-38.41	Main Steam System (Unit 1)
1-PT-38.42	Steam Generator and Feedwater Secondary Systems (Unit 1)
1-PT-38.45	Condensate System (Unit 1)

As a result of this review (and a review of Chemistry Administrative Procedures as discussed in the next section of this report) the inspector believes that this licensee is meeting all of the technical recommendations of the SGOG/EPRI guidelines (and NRC Generic Letter 85-02). As will be discussed later, additional attention should be given to implementing the SGOG/EPRI recommendations related to staffing and maintenance.

c. Implementation of the Surry Water Chemistry Program

The inspector reassessed the licensee's capability for making the chemical measurements necessary for control of the chemical quality of the secondary coolant and for implementing other requirements of the Surry Water Chemistry Program. This evaluation was again based on discussions with licensee personnel, review of procedures, observation of calibrations and chemistry tests, and an audit of results obtained during the past year.

(1) In conjunction with the revision of Periodic Tests the licensee has developed a series of Chemistry Administrative Procedures (CAPs) to provide detailed information and instruction related to the various responsibilities of the Chemistry Section. These documents reference guidance provided by the Nuclear Steam Supply System (NSSS), vendor (Westinghouse), Electric Power Research Institute (EPRI), Institute of Nuclear Power Operations (INPO), and the licensee's corporate chemistry group and are to be used by Chemistry Technicians to fully comprehend their duties and the interface of the Chemistry Section with other departments of the station.

The inspector observed that a formal on-the-job training program had been developed to qualify all Chemistry personnel on the new, state-of-the-art, ion-chromatograph and atomic absorption spectrometer. A Senior Technician has been detailed for this instruction as well as for maintaining these instruments operable and for setting-up new on-line ion chromatographs in the near future.

Another Senior Technician has been detailed to upgrade training in quality control based on CAP 2.0.

In compliance with the SGOG/EPRI guidelines that corrective action should be taken in a timely manner, the licensee now has at least two members of the Chemistry Section on duty at all times. Procedures for notifying plant management and the Operations Department of abnormal chemistry events are detailed in CAP 9.0.

(2) The licensee has entered into a long-term steam generator maintenance agreement with Westinghouse that will significantly affect the implementation of the Surry Water Chemistry Program. Plans are underway to install several types of in-line analytical instrumentation and monitors to supplement the current schedule of 'grab' samples. The inspector expressed two concerns related to this upgrade program. Currently, because of maintenance problems, most of the chemistry monitors on the board in the Control Room are inoperable. The inspector was told by Operations personnel that they would depend on personnel from the Chemistry Section or Water Treatment Section to alert the Control Room of any deviations from normal chemistry and to make recommendations for corrective action. At present, the Chemistry Section does not have any readouts or alarms for in-line monitors. If new in-line instrumentation is to be installed, the alarms and monitors should be located where they will result in timely corrective action being taken - as recommended by the SGOG/EPRI guidelines.

The SGOG/EPRI guidelines also address timely maintenance of instruments and other components that are needed to control and monitor secondary water chemistry. It is the inspector's opinion that the licensee needs to place considerably more attention and resources in this area to ensure that abnormal chemistry events

can be recognized and corrected promptly. The addition of new in-line instrumentation will only add to this work load.

(3) The licensee has developed the capability to trend key chemistry parameters with a computer. Consequently, both graphical and numerical data are available to plant management for diagnosing and controlling transients in secondary water chemistry. The inspector took advantage of this capability to audit the licensee's control of key chemical parameters during the past year. As reported earlier, chemistry control was considered to be very good except during power excursions (hideout return) and during isolated chemistry transients.

The cause of most of the transients were readily explained by Chemistry Section personnel. However, a significant increase in the chloride concentration in only one steam generator occurred on June 29, 1985 while Unit 2 was returning to power, and its cause could not be determined with certainty. The licensee believes the high chloride concentration may have resulted from decomposition of an organic cleaner, Inhibisol, that had inadvertently been left in this steam generator after the girth weld repairs had been completed. The inspector considered this to be a quality control problem.

With the high sensitivity that is now available with ion chromatography the licensee is attempting to identify all anions that contribute to the cation conductivity of steam generator water. These studies, when correlated with the measured cation conductivity of the main steam, indicate that a large percentage of anionic species volatilize with the steam and, thus, may consist, in part, of organic or inorganic carbon compounds. This information will be of use in establishing what species are carried over to the low-pressure turbine rotors.

(4) The inspector observed three Chemistry Technicians while they performed analyses of routine samples by means of ion chromatography, atomic absorption, flame photometry, spectrophotometry, conductivity bridge, and pH meter. All activities, including calibrations of instruments and procedures, were considered to have been performed properly and in a professional manner.

(5) During this phase of the inspection, no violations or deviations were identified.

d. Inspector Followup Items (IFI)

As a result of this inspection, the following followup items have been closed.

IFI 50-280, 281/84-16-01 "Evaluation of Secondary Water Chemistry Program." This item is closed on the basis of new information that is summarized in Section 5.b of this report.

IFI 50-280, 281/84-16-02 "Leakage of Primary Water Into the Component Cooling Water System." During the latter part of his previous inspection the inspector became aware that primary coolant was leaking into the component cooling water system. In the interim this leak has been stopped; however, the component cooling water remains contaminated with reactor cooling water.

6. Inservice Testing of Pumps and Valves

The inspector continued a review of the licensee's activities for implementing the requirements of Section XI of the ASME code to test safety-related pumps and valves. Attention was primarly directed to the licensees procedures for stroke-timing valves and to the summary listing of results from valve stroke-time tests.

To the extent of this review, no deviations or violations were identified. The inspector did question the licensee's policy and procedures for establishing reference and maximum stroke times and discussed the NRC staff's position that stroke times are to be used to establish the operability of only a specific valve rather than the system that includes the valve. After reviewing procedures (Periodic Tests) in which the maximum allowable stroke time was considerably longer (by a factor of 10 to 100) than the measured stroke time, the inspector requested that the maximum stroke times be reviewed to ensure that they were of magnitudes that would allow trends in degradation of the valves to be identified.