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

FEB 0 8 1990

Report Nos.: 50-269/90-02, 50-270/90-02, and 50-287/90-02

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242

Docket Nos.: 50-269, 50-270, and 50-287

License Nos.: DPR-38, DPR-47, and DPR-55

Facility Name: Oconee 1, 2, and 3

Inspection Conducted: January 8-12, 1990

Inspector: Susanne S. Adamovitz — 2/7/90
S. Adamovitz — Date Signed

Approved by: D.M. Collins for — 2-7-90
T. R. Decker, Chief — Date Signed
Radiological Effluents and Chemistry Section
Emergency Preparedness and Radiological
Protection Branch
Division of Radiation Safety and Safeguards

SUMMARY

Scope:

This routine, unannounced inspection was conducted in the areas of plant chemistry with an emphasis on secondary chemistry; pipe erosion/corrosion throughout the secondary system; and an assessment of the steps being taken to prevent degradation of the primary coolant pressure boundary. The inspection also covered the status of the station modifications to the low pressure service water (LPSW) monitors, RIA-31 and -35.

Results:

In the areas inspected, violations or deviations were not identified.

Primary and secondary chemistry parameters had been maintained within Technical Specification requirements and EPRI/SGOG guidelines during steady state operations (Paragraphs 2.a.1 and 2.b).

A Morpholine/AVT secondary chemistry program had been initiated for all three units in an effort to reduce system corrosion and subsequent corrosion products transport to the steam generators (Paragraph 2.b.7).

Unit 3 steam generators were experiencing increased fouling rates. The causes for the increased rate were currently not known and various corrective actions, including chemical cleaning, were being considered (Paragraph 2.b.6).

The LPSW radiation monitors RIA-31 and -35 were still nonfunctional. The expected completion date for a modification to install pressure regulators and upgrade the associated piping had been delayed from January 1990 to October 1990 (Paragraph 4).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

W. Barber, Nuclear Chemistry Specialist
*B. Barron, Station Manager
J. Batton, Associate Engineer
*L. Benge, Supervising Scientist, Chemistry
D. Cantrell, Associate Scientist
*J. Davis, Superintendent of Technical Services
E. Dummeyer, Verification Specialist II
M. Hipps, Nuclear Production Engineer
E. Lampe, Associate Scientist, Radiation Protection
*E. LeGette, Regulatory Compliance
*J. Sevic, Chemistry Manager
*D. Sweigart, Operations Superintendent

NRC Resident Inspectors

*P. Skinner
*L. West

*Attended exit interview

2. Plant Chemistry (84750)

At the time of this inspection, Oconee Units 1, 2, and 3 were operating at 100 percent power. Unit 1 was in its twelfth fuel cycle after a January to February 1989 refueling outage, and Unit 2 was in its eleventh fuel cycle after a May to July 1989 refueling outage. Unit 3 had just completed a planned refueling outage which lasted from November to December 1989 and the unit was in its twelfth fuel cycle. The inspector reviewed the plant chemistry controls and operational controls affecting plant chemistry during 1988 and 1989.

a. Reviews of Reactor Coolant Chemistry Controls

(1) Technical Specification (TS) 3.1.5 requires that the concentrations of oxygen, chloride, and fluoride in the primary coolant be maintained equal to or below 0.1 parts per million (ppm), 0.15 ppm and 0.15 ppm respectively, during power operations. The inspector reviewed 1988 and 1989 data for these chemistry variables and determined that these parameters were maintained well below TS limits for the three units. Typical values for oxygen, chloride, and fluoride when the units were at 100 percent power were less than 5 parts per billion (ppb), less than 50 ppb and less than 50 ppb, respectively. Chloride

and fluoride concentrations were determined by specific ion probes in the primary chemistry laboratory.

(2) The licensee had performed induced crud bursts for the three units during past outages. The crud bursts were accomplished by the addition of hydrogen peroxide to the reactor coolant systems and were designed to reduce out-of-core radiation/contamination levels by solubilizing fission and activation products deposited on out-of-core metal surfaces. Crud burst data for past outages are presented in the table below:

Oconee Crud Burst Data

Date	Co-58 (Curies)	Co-60 (Curies)
Unit 1		
September 1987	1200	9
January 1989	500	24
Unit 2		
February 1988	931	3
May 1989	498	0.18
Unit 3		
August 1988	491	10
November 1988	517	3.6

With the exception of Unit 3, crud burst data showed a substantial decrease in the total number of curies removed from one outage to another. This decrease in the total curies removed was attributed to the licensee's program of maintaining a constant pH in the reactor coolant by coordinated boron/lithium control. Per the Electric Power Research Institute's (EPRI) guidelines, surface corrosion in the primary system is minimized by maintenance of a constant pH.

(3) The licensee performed the following preventive actions to reduce primary side stress corrosion cracking (PSSCC) of the steam generator tubes:

(a) The licensee had adopted an administrative upper limit of 40 cc/kg for hydrogen dissolved in the reactor water. The inspector reviewed graphed hydrogen data covering the past 18 months. Units 1 and 2 hydrogen overpressure numbers typically ranged from 25 to 40 cc/kg with few points between 40 to 50 cc/kg. Unit 3 values ranged from 30 to 50 cc/kg. Graphed data did not show any hydrogen overpressure numbers above 50 cc/kg.

(b) The licensee had incorporated the EPRI guidelines for a coordinated boron/lithium program with a constant pH of 7.1-7.2 at 300°C. At the beginning of cycle, lithium is maintained at 2.2 ppm at 1,200 ppm boron. The licensee was considering increasing the lithium levels to 3.5 ppm during 1990, at the beginning of cycle for Unit 2. This was a proposed modification to the facility's lithium control program and had not been implemented as yet. The inspector reviewed the licensee's procedure CP/0/A/2002/07A, "Control of Lithium in the Reactor Coolant System," dated October 9, 1989. The procedure described the methods for making lithium hydroxide additions to the primary system and included guidelines for maintaining lithium specifications. The inspector also reviewed graphed data for primary system pH values from July 1988 to January 1990. The pH values for all three units were approximately 7.0 at the beginning of the new fuel cycle and slowly increased to 7.1-7.2 during the remainder of the cycle.

b. Review of the Secondary Chemistry Controls and System Operations.

(1) Main Condenser

Eddy current testing was performed every refueling outage by vendor personnel. The scope of the eddy current surveillance program typically included the peripheral tubes of each waterbox tube bundle plus selected tubes in known or suspected damage areas. As a result, approximately 11 percent of the condenser tubes were inspected each outage. For Units 1, 2, and 3, a total of 294, 414, and 572 tubes respectively, had been plugged out of 50,880 tubes per unit. Steam erosion and fretting were identified as the principle damage mechanisms.

Air inleakage above the waterline into the condenser was routinely monitored. The inspector reviewed test procedure PT/0/B/150/28, "Condenser Air In-Leakage Investigation," dated November 25, 1987, which identified plant conditions that would initiate an investigation. These conditions included when a unit's total off-gas flow exceeded 10 SCFM of unidentified leakage, when dissolved oxygen concentrations exceeded 10 ppb in the hotwell, or when dissolved oxygen concentrations exceeded 7 ppb in the final feedwater. The inspector reviewed Chemistry Monthly Summary reports from August 1988 to November 1989, which showed that condenser inleakage values were maintained below 10 SCFM or corrective actions were initiated. The inspector also reviewed 18 months of graphed data for dissolved oxygen levels in the final feedwater and condenser hotwell. At 100 percent power, dissolved oxygen levels typically ranged from 1 to 3 ppb in the final feedwater and from 1 to 5 ppb in the condenser hotwell. These values were below the limits specified in the EPRI PWR Secondary Water Chemistry guidelines. Further evidence of the quality of the water in the condenser hotwells were cation conductivity values which ranged from 0.13-0.18 umho/cm for the three units over an 18 month time period.

(2) Condensate Cleanup Systems

The licensee had experienced few operational problems with the condensate polishers over the past 18 months. The plant did experience one incident of resin leakage during 1989 when a locking device for the cells in Unit 2 broke. This hardware problem allowed some resin leakage but the licensee's system did incorporate a resin trap downstream of the polishers. The licensee indicated that the elements were precoated every 25 days or if the cation conductivity in the final feedwater exceeded 0.2 umho/cm.

The inspector reviewed graphed data for final feedwater parameters from August 1988 to January 1990. For steady state operations sodium and chloride concentrations were less than 1 ppb for the three units. Silica, iron, and suspended solids were typically less than 10 ppb during this time period. These values were within the limits recommended by the EPRI/SGOG.

(3) Water Treatment Plant

The inspector toured the water treatment plant with a licensee representative and discussed maintanance and operation of the plant. The plant was operated by the Environmental group who was a part of the facility's Chemistry Department. The plant had experienced few operational problems during the past year and a half and had continued to produce water of sufficient purity (specific conductivity of 0.055 umho/cm) and quantity to meet the facility's needs under routine and outage conditions. The condensate makeup water was still being stored under deaerated conditions in the Upper Surge Tank.

(4) Service Water Systems

The lake water used in the Low Pressure Service Water (LPSW) and the High Pressure Service Water (HPSW) systems was of sufficient purity that the licensee had not encountered serious problems with pipe fouling by silt or with pipe corrosion by macro-or micro-organisms. Previously, the plant had experienced some silt build-up in selected service water heat exchangers such as the Reactor Building Cooling Unit (RCBU) heat exchangers and had initiated preventive maintenance inspection/cleaning programs. Typically the heat exchangers were performance tested and/or inspected annually or during a refueling outage.

The licensee had also established a program to monitor clam infestation in HPSW and LPSW systems. Chemistry personnel had selected several low flow components within the service water systems which were monitored quarterly for clam infestation. These components included the LPSW and HPSW pump screens, Raw Cooling Water (RCW) heat exchangers, four fire hose stations in the plant, and six fire hydrants. The inspector reviewed 1988 and 1989 quarterly data which showed that the maximum number of clams found in any single area was 15 whole clams and 41 shell fragments. Chemistry personnel indicated that in addition to their surveillance program, Maintenance personnel would also report any indication of clams during routine repair or surveillance activities.

Microbiological induced corrosion (MIC) was also being monitored during routine maintenance activities by visual inspections for evidence of pipe pitting and by analysis of wash water samples from the raw water heat exchangers for sulfate reducing bacteria. Thus far, the licensee had not identified any problems with MIC in the plant's service water systems. Plans were being made to initiate side stream monitoring during 1990 in the LPSW system in order to monitor system corrosion.

(5) Feedwater Heaters

Prior to 1989, eddy current testing of the feedwater heaters had been performed if the heaters were known to have leaking tubes or operational problems. Beginning with the June 1989 Unit 2 refueling outage, eddy current testing was performed on feedwater heater 2A2 based upon past problems and not on any currently identified leakers. Additionally, the licensee planned to continue proactive inspections of the heaters by eddy current testing two or more feedwater heaters during each refueling outage. Initial emphasis would be placed upon the twelve high pressure heaters. Five of the twelve high pressure heaters were replaced several years ago with stainless steel tubes. The remaining seven heaters contained the original carbon steel tubes and previous eddy current technology was not able to test carbon steel. During the June 1989 outage, feedwater heater 2A2, which contains carbon steel tubes, was tested by a vendor using recently developed technology. Since the 2A2 high pressure heater shell had been removed during the outage, visual inspections were performed to substantiate the eddy current test results.

(6) Steam Generators

The inspector and licensee representatives discussed the eddy current testing program for the facility's steam generators. During Unit 1's last refueling outage (January, 1989), 100 percent of the tubes were tested since a base line inspection had not previously been conducted. An additional 62 tubes were plugged in the two Unit 1 steam generators bringing the total number of plugged tubes to 619. The major mechanism for tube damage was by erosion/corrosion in the peripheral tubes. For Unit 2, 51 percent of the tubes were eddy current tested during the May 1989 refueling outage. Nine additional tubes were plugged at this time bringing the total number of Unit 2 plugged tubes to 102. The licensee was planning to perform eddy current testing of 100 percent of the Unit 2 tubes during the next refueling outage. Eddy current testing was performed for 60 percent of the Unit 3 steam generator tubes during November 1989. Twenty additional tubes were plugged and most of these were located in the periphery. The total number of plugged tubes for Unit 3 was 32 percent. One hundred percent of the Unit 3 steam generator tubes had been eddy current tested during 1987 as a baseline inspection.

The licensee had not performed sludge lancing of the steam generators during the past refueling outages. The licensee indicated that the majority of the sludge formed on the generator's upper internals and that sludge lancing would not remove debris from those areas.

Chemical cleaning of the Units 1 and 2 steam generators had been performed in 1987 (Unit 1) and 1988 (Unit 2). The chemical cleaning was prompted by the build up of corrosion products in the tube-tube support plate openings which had restricted water flow through the secondary side of the once-through-steam generators (OTSG) and reduced available power. The chemical cleaning was augmented by subsequent sludge lancing and proved successful in removing thousands of pounds of sludge, mainly magnetite, from the generators. Design flow had been restored to all four steam generators (see Inspection Report (IR) Nos. 50-269/87-40 and 50-269, 270, 287/88-24). The licensee was continuing to monitor steam generator fouling by tracking the generator levels and had seen evidence of an increased rate of fouling for the Unit 3 generators. The inspector reviewed two memorandums, "Steam Generator Level Monitoring," dated March 28, 1989 and September 15, 1989, which summarized trends for the rates of increase. Based upon earlier evidence of the stability of the Unit 3 generator levels, the licensee did not expect chemical cleaning to be required until 1997. With Unit 3's increased fouling rates, chemical cleaning was being planned for 1991 or 1992. The inspector attended a meeting which included plant, general office, and vendor personnel to discuss various methods to deal with the steam generator fouling and potential power restrictions. If equipment and personnel could not be prepared in time to perform chemical cleaning in 1991, a "water slap" treatment followed by sludge lancing was being considered. However, this treatment would provide only temporary relief to the generator fouling and would have to be followed by chemical cleaning during the next refueling outage in 1992.

The licensee performed a hotsoak of the steam generators during the cooldown prior to a refueling outage. The purpose of the hotsoak was to reduce hideout return, which can be defined as chemical containments that collect or "hideout" in steam generator crevices during power operation and then return to the liquid as temperature is reduced. The inspector reviewed hotsoak data for Unit 1 end-of-cycle (EOC) 11 (January 1989) and Unit 2 EOC-10 (May 1989). Silica and sulfate levels decreased for both units as compared to data from the previous EOC hotsoaks. The licensee noted that the chemical cleaning of Unit 2 had apparently not affected the hot soak results with the possible exception of silica.

Primary to secondary leak rates for Units 1 and 3 were currently less than 0.001 gallons per minute (gpm). The Unit 2 leak rate was measured at 0.01 to 0.02 gpm.

(7) Morpholine/All Violate Treatment (AVT) Chemistry

The licensee had conducted a test on Unit 2 during 1989 to determine the effect of morpholine on secondary system corrosion rates. Morpholine had been used in other nuclear facilities to significantly reduce corrosion rates and the subsequent corrosion product transport to the steam generators. The test consisted of the addition of morpholine to the Unit 2 secondary system to achieve a concentration of 5 to 7 ppm and to maintain this concentration for 30 days. Since the unit experienced two power transients during the second week of the test, the time period was extended to 39 days. Corrosion product samplers were used at six sample points which included; final feedwater, hotwell, powdex effluent, moisture separator drain tank, D heater drain tank, and E heater drain tank. Test results showed a 33 percent to 71 percent reduction in iron transport at the various sampling points with the highest percent reduction reported for the final feedwater sampling point. A 70 percent reduction in iron equated to 245 pounds less of magnetite being transported to the steam generators per effective full power year based upon the feedwater concentration. Based upon these results, Units 1 and 2 began the Morpholine/AVT secondary chemistry program in November 1989, and Unit 3 in January 1990.

(8) Summary

The licensee had maintained primary chemistry well within TS requirements and secondary chemistry within the limits recommended by the EPRI/SGOG during steady state operations. Only low levels of ionic contaminants were present in the primary and secondary systems. Air inleakage into the main condenser was continuously monitored such that low levels of dissolved oxygen were present in the condenser hotwell. The licensee had initiated a preventive maintenance program for service water systems which included inspection and cleaning of silt deposits and monitoring for clam infestation. A program was begun to eddy current test the feedwater heaters on a regular schedule rather than test after performance problems had occurred. The licensee had also initiated a Morpholine/AVT secondary chemistry program to reduce system corrosion rates and corrosion product transport to the steam generators.

c. Review of the Licensee's Chemistry Control Program

(1) Staffing

There were no major changes in personnel that staffed the chemistry laboratories since the last inspection in this area.

(2) Procedures

The inspector selected eleven procedures to review from the facility's Chemistry Manual. The procedures that were reviewed covered secondary laboratory sampling, laboratory quality control, data review and documentation of results, MIC monitoring, procedure preparation and control, environmental sampling frequency, computer software control, and guidelines for system startup, shutdown, and corrective actions.

Chemistry Manual Chapter 3.8, "Secondary Lab Sampling Frequencies and Specifications," dated December 6, 1989, continued to endorse and reference guidelines recommended by the SGOG and EPRI. Chemistry Manual Chapter 3.6 "Chemistry Laboratory Quality Control," dated April 26, 1988, identified various crosscheck programs in which a secondary laboratory participated. As indicated in a previous inspection report (IR No. 50-269, 270, 287/88-24), the Chemistry Department participated in an interlaboratory crosscheck program using "round-robin" samples prepared by personnel at the licensee's Central Environmental Laboratory. Samples were provided to several laboratories and the "correct" value for each chemistry variable was still being obtained from the average of all results from the various laboratories, after statistical outliers had been eliminated. The use of a consensus average is considered to be biased by the procedure and instrumentation used and to be inferior to the "known" value obtained through replicate analyses from a laboratory whose results are directly traceable to the National Institute of Standards and Technology.

(3) Facilities and Instrumentation

The inspector and cognizant laboratory personnel toured the licensee's secondary laboratory which contained the facility's newly installed online ion chromatograph. During a previous inspection conducted in May 1989 (IR No. 50-269, 270, 287/89-13), the new secondary laboratory was functional and the online ion chromatograph was installed in the laboratory but was not yet operational. The online ion chromatograph had been functional since May 1989 and contained three analyzers two anion and one cation. The anion analyzers were calibrated to quantify chloride, sulfate, fluoride, acetate and formate ions. The cation analyzers could quantify sodium, ammonia, morpholine, and potassium ions. Laboratory personnel indicated that the ion chromatograph was consistently providing useful data from the 16 sampling points within the three units' secondary systems. However, the analyzer did require constant attention to maintain operability which was consistent with industry experience.

During a previous inspection (IR No. 50-269, 270, 287/88-24), the inspector noted that sulfate was not being monitored in the polisher effluent (to monitor resin leakage), final feedwater (FFW), and moisture separator reheater (MSR) drains. Also chloride was not being monitored in the FFW per SGOG guidelines. During the current inspection, the inspector determined that these analyses had been added to the secondary chemistry monitoring program.

(4) Audits

The inspector reviewed two corporate audits and twelve plant surveillances performed during 1988 and 1989 in the area of plant chemistry. The corporate audits were performed by General Office personnel with the assistance of plant Quality Assurance (QA) personnel. Surveillances were performed by onsite QA personnel and were not as formal as the audits. The QA surveillances and audits were designed to determine compliance with the facility's technical specifications, plant procedures, regulatory guides, and industry standards. The inspector reviewed selected surveillance plans, checklists, and findings, and confirmed that the licensee had a tracking system in place to verify responses to the findings and that subsequent corrective actions were completed and documented. From a review of surveillance reports and discussions with plant QA personnel, the inspector determined that the surveillances were performed by personnel knowledgeable in the chemistry activities at a nuclear power plant. The surveillance checklists were comprehensive for a specific task and attention to detail was evident. The licensee's surveillances and audits were good quality and provided a comprehensive review of the chemistry areas.

No violations or deviations were identified.

3. Semiannual Radioactive Effluent Release Reports (84750)

The inspector reviewed the Semiannual Radioactive Effluent Release Report for the first half of 1989 and discussed the report with licensee representatives. The effluent information presented in Table A was obtained from current and previous effluent reports.

Table A
Effluent Release Summary for
Oconee Units 1, 2 and 3

Activity Released (Curies)	1986	1987	1988	(First Half) 1989
1. Gaseous Effluents				
Fission and Activation Products	2.43E+4	1.05E+4	2.59E+4	5.46E+3
Iodines and Particulates	5.41E-2	1.58E-1	1.88E-1	2.92E-2
2. Liquid Effluents				
Fission and Activation Products	5.85E0	2.90E0	3.10E0	1.74E0
Tritium	1.34E+3	9.49E+2	7.10E+2	4.54E+2

Gaseous releases had decreased during the first half of 1989, and this decrease was partially attributed to fewer batch releases. Also Unit 3 experienced a tube leak outage during 1988 which would have increased gaseous effluents.

No violations or deviations were identified.

4. Effluent Monitoring Instrumentation (84750)

The inspector checked the status of the LPSW monitors, RIA-31 and -35. As indicated in a previous inspection (IR No. 50-269, 270, 287/89-13), conducted May 1989, the Units 1, 2, and 3 liquid monitors, RIA-35's, had been reported in the Seminannual Effluent Release Reports as being consistently inoperable since 1986. The functions of the RIA-31 and -35 were to monitor six LPSW cooling systems which were used to cool several radioactive systems throughout the plant. The licensee had experienced consistent problems with low flow alarms on the monitors and during 1988, had cleaned or replaced several sample lines, RIA coolers, and valves. The licensee had also determined that the sampler could not correct for differing pressure among the six cooling systems and had initiated nuclear station modification (NSM) 2737 to upgrade the associated piping and install pressure regulators. The expected completion date for that portion of the NSM was January 1990. During the current inspection, the inspector determined that the modifications had not been implemented and were not expected to be completed for all 3 units until October 1990. The RIA-35 is a TS required monitor and it's inoperability has put the licensee in an Action Statement requiring 12 hour grab sampling and analysis. The inspector and licensee representatives discussed the importance of maintaining increased attention to this problem.

No violations or deviation were identified.

5. Exit Interview

The inspection scope and results were summarized on January 12, 1990, with those persons indicated in Paragraph 1. The inspector described the areas inspected and discussed in detail the inspection results listed below. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Primary and secondary chemistry parameters had been maintained within TS requirements and EPRI/SGOG guidelines during steady state operation (Paragraphs 2.a.1 and 2.b).

The licensee had increased the facility's monitoring capabilities of secondary system parameters by the installation of an online ion chromatograph (Paragraph 2.c.3).

Sulfate analyses for the polisher effluent, FFW and MSR drains had been added to the secondary chemistry program. Also chloride analyses in the FFW had been implemented per SGOG guidelines. (Paragraph 2.c.3)
A Morpholine/AVT secondary chemistry program had been initiated in an effort to reduce system corrosion and subsequent corrosion product transport to the steam generators (Paragraph 2.b.7).

Unit 3 steam generators were experiencing increased fouling rates. The cause for the increased rate was currently not known and various corrective actions including chemical cleaning were being considered (Paragraph 2.b.6).

The LPSW radiation monitors RIA-31 and -35 were still nonfunctional. The expected completion date for a modification to install pressure regulators and upgrade the associated piping had been delayed from January 1990 to October 1990 (Paragraph 4).