October 29, 1998

Mr. William R. McCollum, Jr.
Vice President, Oconee Nuclear Site
Duke Energy Corporation
P. O. Box 1439
Seneca, SC 29679

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE OCONEE NUCLEAR STATION, UNITS 1, 2, AND 3, LICENSE RENEWAL APPLICATION

Dear Mr. McCollum:

By letter dated July 6, 1998, Duke Energy Corporation (Duke) submitted for the Nuclear Regulatory Commission's (NRC's) review an application pursuant to 10 CFR Part 54, to renew the operating licenses for the Oconee Nuclear Station (Oconee), Units 1, 2, and 3. Exhibit A to the application is the Oconee Nuclear Station License Renewal Technical Information Report (OLRP-1001), which contains the technical information required by 10 CFR Part 54. The NRC staff is reviewing the information contained in OLRP-1001 and has identified, in the enclosure, areas where additional information is needed to complete its review of the following OLRP-1001, Section Numbers: 3.4.11, 3.5.9, 4.3.2, 4.3.8, 4.3.9, 4.6.2, 4.6.3, 4.6.4, 4.21, and 5.7.1.

Please provide a schedule by letter, electronic mail, or telephonically for the submittal of your responses within 30 days of the receipt of this letter. Additionally, the staff would be willing to meet with Duke prior to the submittal of the responses to provide clarifications of the staff's requests for additional information.

Sincerely,

Original Signed By

Stephen T. Hoffman, Senior Project Manager
License Renewal Project Directorate
Division of Reactor Program Management
Office of Nuclear Reactor Regulation

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

Enclosure: Request for Additional Information

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REQUEST FOR ADDITIONAL INFORMATION
OCONEE NUCLEAR STATION, UNITS 1, 2, AND 3
LICENSE RENEWAL APPLICATION, EXHIBIT A

OLRP-1001 Section No.

3.4.11 Class 1 Component Supports

3.4.11-1 What action did you take in response to Generic Letter 91-17, Generic Safety Issue 29, "Bolting Degradation or Failure in Nuclear Power Plants?"

3.4.11-2 Based on the staff's experience, degradation of bolted connections (e.g., loose bolts) potentially caused by vibration loading, is a common type of aging effect of component supports with bolted connections. Clarify whether this loading effect has been considered in the aging review for the Class 1 component supports, and (if this effect is excluded) provide the basis for excluding this effect.

3.4.11-3 Table 3.4-1 does not identify any applicable aging effects for the reactor coolant pump motor vertical and lateral support assemblies due to loading from rotating/reciprocating machinery. However, the loss of preload due to rotating/reciprocating machinery has been identified as a potentially applicable aging effect for component supports and, in particular, for the reactor coolant pump motor vertical and lateral support assemblies. Identify the specific location in the license renewal application (LRA) that the loss of preload and the related aging management program(s), and demonstration are discussed, or provide a technical justification for not identifying loss of preload due to rotating/reciprocating machinery as an applicable aging effect for reactor coolant pump motor vertical and lateral support assemblies.

3.4.11-4 Are there any parts of Class 1 component supports described in Section 3.4.11 that are inaccessible for inspection? If so, describe what aging management program will be relied upon to maintain the integrity of inaccessible areas. If the aging management program for inaccessible areas relies on an evaluation of the acceptability of conditions in surrounding accessible areas, please provide information to show that conditions that exist in accessible areas reasonably reflect those conditions that are likely to exist in inaccessible areas. If different aging effects or aging management techniques are needed for inaccessible areas, please provide a summary of your actions to address the following elements concerning inaccessible areas: (1) preventive actions that will mitigate or prevent aging degradation; (2) parameters monitored or inspected relative to degradation of specific structure and component intended functions; (3) detection of aging effects before loss of structure and component intended functions; (4) monitoring, trending, inspection, testing frequency, and sample size to ensure timely detection of aging effects and corrective actions; (5) acceptance criteria to ensure fulfillment of structure and component intended functions; and (6) operating experience that provides objective evidence to demonstrate that the effects of aging will be adequately managed.

3.4.11-5 Table 3.4-1 indicated that the potential aging effect of cracking of lubrite pads for the once-through steam generator (OTSG) upper lateral support structure will be managed by the OTSG lateral support inspection program. Section 4.3.6 indicated that the subject inspection program is a one time inspection and it will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1). It is also stated that lubrite pads that are found cracked will be replaced with new pads. Provide the basis for not performing periodic inspections to track any future potential pad cracking due to radiation effects during the period of extended operation. If applicable, please include a discussion of how the plant operating and maintenance history support this conclusion.

3.4.11-6 Are there any Class 1 component supports described in Section 3.4.11 containing pins, springs, or sliding plates? If so, provide the basis for excluding mechanical wear as a potential aging effect for those component supports.

3.4.11-7 Section 3.4.3.4 indicated that there was an instance of cracking of a weld in a drain line off the pressurizer surge line. It further stated that the root cause of the weld cracking was determined to have been a combination of stress corrosion and mechanical vibration. Provide a summary description of the subsequent corrective actions to prevent the mechanical vibration for the subject piping systems, as well as their associated supports, that may be affected by mechanical vibration. Also, indicate if these corrective actions are applicable to the period of extended operation. If not, provide the basis for your determination.

3.5.9 <u>Steam and Power Conversion Systems</u>

3.5.9-1 The steam and power conversion system comprises four systems with components made of materials which may undergo degradation by different types of corrosion mechanisms when exposed during plant operation to the environments of raw or treated water. Your aging management program is designed to control this degradation by (a) controlling the relevant conditions that would lead to the onset and propagation of these aging effects and (b) by performing inspections and analyses verifying the integrity of the piping systems. Describe these inspections and analyses and show how they will permit you to evaluate integrity of the piping and other components in the steam and power conversion system.

3.5.9-2 For the condensate cooler tubing and main condenser tubing examinations, provide the scope of the examination, the examination method, the acceptance criteria, the frequency of such examinations and relevant Oconee-specific operating experience related to the performance of the condensate coolers and main condensers to date. Provide the bases to show how these examinations are appropriate for timely detection of aging effects.

3.5.9-3 Portions of the main steam system and the feedwater system are located in the Auxiliary Building. As described in Section 3.5.2.7.2, the Boric Acid Wastage Surveillance Program is cited to manage loss of material due to exposure to borated water/boric acid for components located in the Auxiliary Building. However, the LRA indicates that the scope of the Boric Acid Wastage Surveillance Program is limited to the Reactor Building. Identify where in the LRA that the Boric Acid Wastage Surveillance Program includes all applicable portions of the main steam and feedwater systems or discuss how loss of material due to boric acid wastage is managed for components of the main steam and feedwater systems located in the Auxiliary Building.

3.5.9-4 Section 3.5.9 of the license renewal application states the applicable aging effects for the following systems:

- Main Steam System components, including piping and valves;
- Condensate System components, including the main condenser, the condensate coolers and the generator water coolers;
- Emergency Feedwater System, including piping and valves; and
- Feedwater System, including piping and valves.

The LRA also states that the related aging effects will be managed by monitoring and controlling the effects directly. In addition, inspections and analyses are performed to investigate and verify the integrity of the piping systems. In Section 3.5.9.4.3, the licensee identifies the Chemistry Control Program and the Piping Erosion/Corrosion Program as the appropriate means to manage the applicable aging effects. However, the LRA, Section 3.5.2, identified cracking due to vibration as a potential aging effect.

For each of these systems, provide the following information:

1. A description of the methods and equipment that will be used for monitoring and controlling the aging effects combined with mechanical vibrations.
2. A description of the inspection and analysis performed to investigate and verify the integrity of the piping systems, including piping and component supports, for combined aging effects and mechanical vibrations.

4.3.2 Cast Iron Selective Leaching Inspection

4.3.2-1 If the Brinell Hardness check indicates that selective leaching has occurred in an inspected cast iron component, what methods will be used to determine the amount of material lost and ensure that it did not exceed the limit required for qualifying the component for further service?

4.3.8 Preventive Maintenance Activity Assessment

4.3.8-1 It is the staff's understanding that Section 4.3.8, "Preventive Maintenance Activity Assessment" is the aging management program to which the licensee refers in the Chapter 3 descriptions as "Preventive Maintenance Activities." With that assumption, the staff expected to find in Section 4.3.8 a description of various aging management programs (including inspection activities, schedules, acceptance criteria, etc.). Instead, Section 4.3.8 contains a description of a program that will assess the effectiveness of various preventive maintenance activities by the end of the licensee's current operating license. Clarify the intent of the subject "program" and discuss how it differs from Oconee's current self-assessment program. Provide a description of the preventive maintenance program(s) that will be used to manage the applicable aging effects in the LRA. Discuss whether the specific inspections listed in Table 4.3-1 are considered aging management programs unto themselves.

4.3.8-2 An aging effect for the Auxiliary Service Water Piping (Table 4.3-1) is described as "[f]ouling due to macro-organisms and silting has been identified as an applicable aging effect for specific portions of the Auxiliary Service Water System piping...." This aging effect is not consistent with the aging effect described in Section 3.5.6.2, "Auxiliary Service Water System" that describes the applicable aging as the "loss of material for the subject components exposed to an air environment will be...." Provide a clarification of the aging effects and the applicable aging management program such that the staff can evaluate that the effects of aging are being managed consistent with the current licensing basis.

4.3.8-3 Table 4.3-1, "Preventive Maintenance Activities," describes aging effects for the Component Cooling System and identifies a component cooler tubing examination. However, Section 3.5.4.2, "Component Cooling System" contains no reference to Preventive Maintenance Activities. Clarify the discrepancy.

4.3.8-4 Table 4.3-1, "Preventive Maintenance Activities," contains the following description for the aging effects of the Reactor Building Cooling Unit Tubing: "Loss of material due to general and localized corrosion of the tube side exposed to raw water and localized corrosion due to galvanic corrosion and boric acid wastage...." This description is not consistent with the description given in Section 3.5.3.1, "Reactor Building Cooling System," that cites preventive maintenance activities to prevent "loss of material...exposed to a ventilation air environment..." The loss of material due to a ventilation air environment is not discussed in Table 4.3-1. In addition, the loss of material due to galvanic corrosion and boric acid wastage corrosion is not discussed in Section 3.5.3.1. Clarify these discrepancies.

4.3.8-5 Table 4.3-1, "Preventive Maintenance Activities," contains the following description for the aging effects associated with the carbon steel strainers in the Turbine Generator Cooling Water System: "Loss of material due to general and localized corrosion...." Confirm that the "filters" listed in Table 3.5-11, "Applicable Aging Effects for Components of Keowee Hydroelectric Station Systems" are the same components called “strainers” in Section 4.3.8, “Preventive Maintenance Activities Assessment.”

In addition, Section 3.5.13.7, “Turbine Generator Cooling Water System” discusses fouling as an applicable aging effect. Stainless steel strainers are included in Table 3.5-11. Fouling is not considered as an aging effect in Table 4.3-1. Discuss why fouling of stainless steel strainers are not identified as an applicable aging effect in Table 4.3-1.

4.3.8-6 In Table 4.3-1, “Preventive Maintenance Activities,” the aging effect for the Condensate Cooler Tubing examination differs from that for the Main Condenser Tubing examination. Explain why micro biologically influenced corrosion is considered for one and not the other although the materials and environment appear to be similar. Discuss why fouling is not considered an applicable aging effect for the portions of the condensate system exposed to a raw water environment.

4.3.9 Reactor Building Spray System Inspection

4.3.9-1 In Section 3.5.3.2, “Reactor Building Spray System,” the LRA states that “the loss of material and cracking for the stainless steel components exposed to an air environment have not been fully characterized and their applicability will need to be verified by a one-time inspection [the Reactor Building Spray System Inspection].” The Reactor Building Spray System is not included in Section 3.5.2.6 “Applicable Aging Effects for a Ventilation Air Environment.” In Section 3.5.2.6, the LRA also states that “stainless steel materials in the plant air environments are resistant to general corrosion.” Clarify these discrepancies.

In addition, Section 4.3.9 identified “the loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel components...exposed to a borated water environment....” These aging effects are not identified in Section 3.5.3.2. Clarify this discrepancy.

4.3.9-2 The Reactor Building Spray System Inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1). The staff finds this date to be unacceptable without additional information. Provide a justification for not completing the inspection activities at the time of application. Along with your justification, describe the methodology, identify any applicable acceptance criteria, identify planned corrective actions, and provide a schedule for implementation.

4.3.9-3 Explain whether the Reactor Building Spray System Inspections provide for sample expansion or follow up inspections if unacceptable indications are. If not, please justify.

4.3.9-4 Please discuss the confirmation process for the Reactor Building Spray System Inspections, i.e., when corrective actions are completed, what are the follow up activities that are done to confirm that the corrective actions are completed, a root cause determination is performed, and recurrence is prevented. (The discussion of this element in your quality assurance program was not clear, stating that it applied to "more significant events.")

4.3.9-5 For Reactor Building Spray System Inspections, discuss Oconee or applicable industry operating experience from similar programs or inspection techniques used to develop this inspection program.

4.6 Chemistry Control Program

Primary Water Chemistry :

4.6.2-1 Were there any instances during operation of the plant when the control parameters for primary water chemistry exceeded EPRI's Corrective Action Level 3, which, according to EPRI guidelines required immediate plant shutdown? If such incidents have occurred, specify the parameters that exceeded the Action Level 3 limits. Identify any noted effects on the plant from these incidents, and identify any programmatic or corrective actions taken.

4.6.2-2 Describe which of the following chemistry regimes were used in controlling pH in the reactor coolant system:

- Coordinated Chemistry
- Modified Chemistry
- Elevated Lithium Chemistry

4.6.2-3 Describe the frequency of sampling for chloride and sulfate in the spent fuel pool and provide maximum acceptable concentrations for these impurities.

4.6.2-4 Were there any significant corrosion incidents (i.e., causing replacement or major repair of a component) in the past affecting carbon steel components exposed to the borated water in the spent fuel pool and its supporting systems? If such incidents have occurred, describe them.

Secondary Water Chemistry :

4.6.3-1 What are the maximum allowable concentrations of silica and iron required by your secondary water chemistry specifications?

4.6.3-2 Were there any significant secondary water chemistry excursions (i.e., greater than level 3 excursions according to EPRI guidelines) in the past? If such excursions have occurred, describe any significant impact on the condition of the plant, such as increased potential for corrosion damage of the components in the secondary water system.

Component Cooling Water Chemistry :

4.6.4-1 Provide the limits, target values, and inspection frequencies for water chemistry parameters monitored for the component cooling system. Also, generally describe the procedures that are used to maintain the chemistry parameters within these values.

4.21 Piping Erosion/Corrosion Program

4.21-1 Describe your erosion/corrosion program by providing the following information:

a. Provide a description of the methodology for predicting degradation of the components in the Main Steam and Feedwater Systems,

b. Identify any predictive codes, such as CHECWORKS or other similar codes, used in the program,

c. Describe the methods used for trending material loss in the components susceptible to erosion/corrosion,

d. Describe any other predictive methods, besides computer codes, which may be used in the program, and

e. Describe the inspection methods used in determining the degree of degradation for the components determined to be affected by erosion/corrosion.

4.21-2 Were there any other types of components within the scope of components requiring aging management review other than straight pipes (e.g., valves/pump bodies, elbows, "T" connections, etc.) included in the erosion/corrosion program? If there were none, provide a justification for excluding them from the program. If they were included, describe any unique inspections in the erosion/corrosion program for these components.

4.21-3 List any significant component failure caused by erosion/corrosion that may have occurred in the past in the systems included in your license renewal application. Identify the component, and date of occurrence.

4.21-4 For the components that failed due to erosion/corrosion, describe the corrective actions including replacement by materials resistant to erosion/corrosion damage (e.g., chrome-moly).

4.21-5 Describe any special training provided to the personnel responsible for managing the erosion/corrosion program?

5.7.1 Polar Crane

5.7.1-1 It is stated in Section 5.7.1 of the license renewal application that Oconee installed an Independent Spent Fuel Storage Installation (ISFSI), which became operational in 1990. The operation of the ISFSI required additional lifts by the spent fuel pool cranes near their rated lifting capacity. This resulted in a reevaluation of the fatigue concerns for the polar cranes through 60 years of operation. Even though the results of this reevaluation indicate that the number of estimated heavy lifts will remain below the specified threshold of 20,000 cycles, the concern remains that similar changes in the operation of the polar cranes may occur in the future that may result in additional lifts and invalidate the current estimates. Describe the tracking mechanisms and/or procedural controls that are in place that may trigger a reevaluation of the estimated heavy lifts, if changes occur in the future operation of the polar cranes.

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