November 24, 1999

LICENSEE: Duke Energy Corporation (Duke)

FACILITY: Oconee Nuclear Station, Units 1, 2, and 3

SUBJECT: SUMMARY OF DISCUSSIONS BETWEEN THE U.S. NUCLEAR REGULATORY COMMISSION (NRC) STAFF AND DUKE REPRESENTATIVES REGARDING MECHANICAL SYSTEMS ASSOCIATED WITH THE OCONEE LICENSE RENEWAL APPLICATION (LRA)

By letter dated September 30, 1999, Duke submitted summary descriptions of changes to the current licensing basis that materially affected its LRA. As a result of these changes Duke added several systems, structures, and components (SSCs) to the scope of license renewal. Enclosure 1 contains questions from the NRC staff regarding the aging management review for the mechanical systems associated with the additional SSCs. Enclosure 1 also documents Duke's response to the staff's questions.

In addition, the safety evaluation report (SER) for the Oconee LRA contained open items 3.1.1-1 and 3.2.12-1. The SER open items concerned the aging effect inconsistencies in the license renewal application and the standby shutdown facility heating, ventilation and air conditioning coolers, respectively. Duke submitted its response to these open items in a letter dated October 15, 1999. The staff requested clarification of Duke's responses to these open items. Enclosure 2 and 3 contain the staff's questions and Duke's responses to the questions associated with SER open item 3.1.1-1, and 3.2.12-1, respectively. The staff believes that Duke's responses contained in Enclosures 1, 2, and 3 resolves the staff's questions.

Original Signed By

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

Enclosure: As stated (4)

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Plant Modification to add Essential Siphon Vacuum System, Siphon Seal Water System, Essential Siphon Vacuum Trenches, and Essential Siphon Vacuum Building

1. The SSW system provides an "operating liquid" for the ESV pumps — the operating liquid is water, right?

Response:
Correct. The operating liquid is raw water.

2. You stated that you plan to rely, in part, on the "Service Water Piping Corrosion Program (*as modified*)" to manage aging effects for the ESV and SSW systems. Describe what you mean by "as modified."

Response:
The Service Water Piping Corrosion Program was modified in response to Open Item 3.2.13-1 through 3.2.13-4 in the 10/15/99 Duke letter.

3. [a] How are the aging management programs (AMPs) being revised to incorporate these two new systems? [b] For example, what is the frequency of system performance testing for the SSW system? [c] How will the parameters monitored as part of this AMP change? [d] How will the scope of the Service Water Piping Corrosion Program be increased? [e] What relevant operating experience can you provide us about these systems?

Response:
(a) This is a generic question. I believe the detailed questions follow.
(b) The system performance testing for the SSW System is performed quarterly.
(c) (Assume referring to System Performance Testing.) The parameters monitored are similar to those described in the System Performance Testing described in the Application. In this case, as is the case for most system performance tests, a procedure is written for the SSW System that sets up design basis conditions, to the extent possible, and monitors parameters associated with system performance, such as flow and pressure.
(d) There are no plans at this time to increase the scope of the Service Water Piping Corrosion due to the addition of the SSW System. The Service Water Piping Corrosion Program inspects sample locations in various raw water systems. The SSW System is newly installed and would therefore not serve as a valuable system for an inspection location. Inspection locations in systems that have been in service since original plant startup provide aging management for the raw water systems.
(e) The system was added to the plant less than one year ago. There is no relevant operating experience for these systems.

Revised SGTR Accident Analysis

1. We need to rewrite portions of our description of the low pressure service water system to accommodate the September 30, 1999 information. We will add the component cooling system and separate it from the description of the low pressure service water system. To ensure consistency, we need to clarify what external environment(s) exist for

the low pressure service water system. We understand that the component cooling system is exposed to the reactor or auxiliary building. What portions of the low pressure service water system are also exposed to these environments?

Response:
The scope of the Low Pressure Service Water (LPSW) System has not changed. Some additional clarification/information: The component coolers are shell-and-tube heat exchangers with Component Cooling through the shell side and LPSW through the tube side. In the Application, only the LPSW portion (tube side) was within scope for system pressure boundary concerns. Therefore the component coolers were listed in the LPSW section of the Application. Due to the reanalyzed SGTR accident, the Component Cooling (shell side) was added to scope and the heat transfer function required (per the 9/30/99 letter). Thus, the hardware scope of the LPSW system has not changed. The only change related to the LPSW System and the component coolers is that fouling of the tubes is now an applicable aging effect, since the heat transfer function is now required.

2. Discuss why you don't consider fouling to be an applicable aging effect for the heat exchanger channel heads and tubesheet exposed to raw water. Also, fouling in raw water systems appears to be treated differently throughout the LRA, and it would be helpful to the staff if you could explain the logic that goes into deciding whether or not fouling is an applicable aging effect.

Response:
Based on Oconee operating experience, fouling is a concern in piping and components 2-inches or less in diameter. Oconee has not had a problem of larger components fouling to the point of insufficent flow. Therefore, fouling is a concern in small diameter components and heat exchanger tubing, but not for channel heads and tube sheets.

3. How can the chemistry control program manage corrosion for the carbon steel tank exposed to air? This is not consistent with your treatment of other carbon steel tanks exposed to air where you relied upon inspection (e.g., tank in low pressure injection system, Keowee governor air system).

Response:
The water in the component cooling surge tank is treated with a corrosion inhibitor. The corrosion inhibitor is of the passivating type that forces a protective layer in the metal. It is expected that the air portions of the tank will have also been passivated due to splash and varying water levels.

4. Why are you changing the AMP for the heat exchanger channel heads and tubesheet from the PM activity (which you are still going to do for the tubes) to the service water piping corrosion program and galvanic susceptibility programs?

Response:
The alteration of aging management programs for the subcomponents of the heat exchanger was not due to the SGTR reanalysis. The Preventive Maintenance Activity manages loss of material of only the tubes in this heat exchanger. The Service Water Piping Corrosion Program manages

loss of material of the channel heads and tubesheet and the Galvanic Susceptibility Inspection manages galvanic corrosion of the channel heads.

5. [a] How are the AMPs being revised to incorporate the additional component cooling components? [b] For example, how will the scope of the Galvanic Susceptibility Inspection change as a result of the addition of the HXR channel heads to the program? [c] How will the scope of the Treated Water Stainless Steel Inspection change? [d] For the heat exchanger performance testing, verify you measure flow rates and temperature differences across the component coolers, provide the frequency of testing of these coolers, describe the acceptance criteria for the testing of these coolers, and provide any operating experience to date for this program relative to the component coolers.

Response:

(a) This is a generic question. I believe the detailed questions follow.

(b) The Galvanic Susceptibility Inspection uses a sample of inspection locations in its methodology. The LPSW System is already within the scope of the Galvanic Susceptibility Inspection. The number of sample inspection locations will not change based on the component cooling channel heads. The results of the sample inspections will apply throughout the system.

(c) The Treated Water Stainless Steel Inspection uses a sample of inspection locations in its methodology. The Component Cooling System is already within the scope of the Treated Water Stainless Steel Inspection. The number of sample inspection locations will not change based on the additional Component Cooling scope. The results of the sample inspections will apply throughout the system.

(d) The heat exchanger performance testing that manages fouling of the component coolers is part of a system test that monitors flow through the component coolers. The test is performed every refueling outage. Temperature differences across the coolers are not monitored during the test. The flowrates are simply recorded and used by the system engineer for trending. An integrated heat transfer test like those of the Decay Heat Coolers or Reactor Building Cooling Units is not necessary, because the component coolers are in operation at or above design basis conditions during normal unit operation. Through a search of problem investigation reports, it appears that there have been no fouling concerns with the component cooler tubes.

<u>Functional Change of the Reactor Building Auxiliary Coolers</u>

1. Discuss the operability concerns with the coolers.

Response:

The RB auxiliary coolers form part of a closed loop inside containment that serves a containment pressure boundary function. The operability concerns were related to maintaining the pressure boundary integrity of the cooler tubes under postulated off-normal loading conditions. The concerns emerged out of Oconee's evaluation for response to GL 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions."

2. Why isn't heat transfer not a required system intended function for license renewal? Don't these coolers function to control containment temperature?

Response:
Heat transfer is not a required system intended function for the reactor building auxiliary coolers. Other than containment boundary, the coolers do not perform any other function that meets the 10 CFR 54.4 scoping criteria. During and following accidents, it is assumed that these coolers are not in operation. In fact, at the time of the Application submittal, the coolers were isolated from the system and had remained isolated for some time pending resolution of the above operability concerns.

3. Why isn't fouling considered an aging effect for those portions of the system exposed to raw water? Even if heat transfer is not a required function, doesn't fouling interfere with flow rates?

Response:
Since the only function required by the coolers is pressure boundary, fouling is not an applicable aging effect. Fouling does not affect pressure boundary capability of the components.

4. Does the visual inspection portion of the PM activity include an inspection of the internal surfaces of the tubes? If it doesn't, you won't detect loss of material until it is through wall (and thus already lost pressure boundary integrity).

Response:
The visual inspection includes an inspection of the internal surfaces of the tubes, as described in the "Scope" section of Table 3-2 of the 9/30 amendment.

5. How are these tubes repaired if found defective through the PM activity?

Response:
Currently, if leakage is detected, generally a cooling coil is removed from service until it can be replaced. In the new inspection activity, if defects are found, engineering evaluation will be required to determine appropriate corrective action.

4. Most PM activities have actually been performed for a long time at Oconee, even if they have been performed on an informal basis. Provide any relevant operating experience for the auxiliary coolers and the associated PM activity.

Response:
This activity is truly a new activity for license renewal. Although it is true that other Preventive Maintenance Activities credited in license renewal have been performed for a long time on an informal basis, this preventive maintenance activity has not been performed on these non-safety coolers in the past. The coolers are monitored for leakage for containment integrity purposes, but the inspection will be a new activity whose intention is to manage the aging of the coolers before leakage occurs.

Followon Questions Associated with Safety Evaluation Report Open Item 3.1.1-1

Note: The following three questions are associated with Duke's response to SER Open Item 3.1.1-1, in particular their response regarding raw water environment.

1. It would be very helpful for the staff if Duke explained how they approach fouling in general for their raw water systems. The staff believes that this same question was asked earlier. This issue comes up again in staff's review of their response to this question. The staff understands their approach to fouling with respect to heat exchanger functions. The staff does not understand how Duke handled fouling and the possible effect on flow rates - it is this aspect the staff would most like Duke to discuss.

RESPONSE: Based on Oconee operating experience, fouling is a concern in piping and components 2-inches or less in diameter. Oconee has not had a problem of larger components fouling to the point of insufficent flow. Therefore, fouling is a concern in small diameter components and heat exchanger tubing.

2. The staff does not understand the 4th full paragraph on p. 61 of the October 15, 1999 submittal. How does "normal operation of the cast iron pump" lead on to conclude that fouling is not likely?

RESPONSE: Based on operating experience, fouling of components at Oconee is due to corrosion products and silt. Fouling due to macro-organisms such as clams that has resulted in a loss of function has not been a concern. Typically, the highest velocities, turbulence, and energy is found in the pump casing. Due to the nature of the fouling occurring at Oconee, it is expected that velocities, turbulence, and energy of the system in the pump casing would not allow corrosion products and silt to settle out and foul the pump casing.

3. With respect to the 2nd full paragraph on p. 61 of the October 15, 1999 submittal, the staff believes that heat transfer is a component intended function, as documented in the September 30, 1999 submittal. Please confirm or clarify this for the staff.

RESPONSE: Heat transfer is a component intended function of the component coolers. In addition, fouling is also an applicable aging effect for these coolers. The correct information is in the September 30, 1999 submittal.

Followon Question Associated with Safety Evaluation Report Open Item 3.2.12-1

It appears to the staff that Duke is taking the SSF water-cooled condensers out of the scope of the Heat Exchanger Performance Testing Program and placing them and the air cooling coil into a new Preventive Maintenance Activity. Duke needs to confirm whether or not this is the case.

RESPONSE: The new Preventive Maintenance Activity manages loss of material. Fouling of the water-cooled condensers is still managed by the Heat Exchanger Performance Testing Program.

Discussions Regarding SER Open Item 3.6.2.3.2-1

In a discussion held with Duke on October 22, 1999, the staff asked Duke to clarify if they plan to inspect the copper tubing and stainless steel valves as part of their inspection of the reactor coolant pump oil collection tank. The staff could not tell from Duke's response whether they plan to inspect these components or not.

Note: The following is an E-mail from Duke regarding this issue

From: "Robert L Gill Jr" <rlgill@duke-energy.com>
To: OWFN_DO.owf4_po(JMS3)
Date: Fri, Oct 22, 1999 9:49 AM
Subject: SER Open Item 3.6.2.3.2-1 Supplement

In response to our telecon on 10/22/99

Background:
The size of each RCP Oil Collection Tank is 150 gallons. This about the size of three 55 gallon drums. The design of the carbon steel tank and attached tubing and piping selected for inspection may be such that the interior surfaces of the copper tubing and the interior surfaces of the stainless steel valve attached to the carbon steel piping may not be visible from the interior of the tank. The copper tubing is attached to a carbon steel nozzle which is attached to the tank. The stainless steel valve is attached to a length of pipe that is attached to the tank.

I propose to supplement our response to SER Open Item 3.6.2.3.2-1 with the following revised statement. Please advse if it is accpetable.

A visual inspection of the bottom half of the interior surface of the carbon steel tank, including visible portions (if any) of copper alloy instrument tubing and stainless steel tank drain valves, will be performed to determine the presence of corrosion.

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