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RA-22-0124
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10 CFR 50.4
10 CFR Part 54

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Subject: Duke Energy Carolinas, LLC (Duke Energy)
Oconee Nuclear Station (ONS), Units 1, 2, and 3
Docket Numbers 50-269, 50-270, 50-287
Renewed License Numbers DPR-38, DPR-47, DPR-55
Subsequent License Renewal Application
Responses to NRC Request for Additional Information Set 4

References:

1. Duke Energy Letter (RA-21-0132) dated June 7, 2021, Application for Subsequent Renewed Operating Licenses, (ADAMS Accession Number ML21158A193)
2. NRC Letter dated July 22, 2021, Oconee Nuclear Station, Units 1, 2, and 3 - Determination of Acceptability and Sufficiency for Docketing, Proposed Review Schedule, and Opportunity for a Hearing Regarding Duke Energy Carolinas' Application for Subsequent License Renewal (ADAMS Accession Number ML21194A245)
3. NRC E-mail dated September 22, 2021, Oconee SLRA - Request for Additional Information B2.1.27-1 (ADAMS Accession Number ML21271A586)
4. Duke Energy Letter (RA-21-0281) dated October 22, 2021, Subsequent License Renewal Application, Response to Request for Additional Information B2.1.27-1 (ADAMS Accession Number ML21295A035)
5. NRC E-mail dated November 23, 2021, Oconee SLRA – Request for Additional Information - Set 1 and Second Round Request for Additional Information RAI B2.1.27-1a (ADAMS Accession Number ML21327A277)
6. Duke Energy Letter (RA-21-0332) dated January 7, 2022, Subsequent License Renewal Application Responses to NRC Request for Additional Information Set 1 and Second Round Request for Additional Information B2.1.27-1a (ADAMS Accession Number ML22010A129)
7. NRC E-mail dated January 11, 2022, Oconee SLRA – Request for Additional Information - Set 2 (ADAMS Accession Numbers ML22012A043 and ML22012A042)
8. Duke Energy Letter (RA-22-0036) dated February 14, 2022, Subsequent License Renewal Application Responses to NRC Request for Additional Information Set 2 (ADAMS Accession Number ML22045A021)
9. NRC E-mail dated January 18, 2022, Oconee SLRA – Request for Additional Information Set 3 (ADAMS Accession Numbers ML22019A103 and ML22019A104)
10. Duke Energy Letter (RA-22-0040) dated February 21, 2022, Subsequent License Renewal Application Responses to NRC Request for Additional Information Set 3 (ADAMS Accession Numbers ML22052A002)

11. NRC E-mail dated March 21, 2022, Oconee SLRA – 2nd Round RAI B4.1-3 (ADAMS Accession Numbers ML22080A077 and ML22080A079)
12. Duke Energy Letter (RA-22-0129) dated April 20, 2022, Subsequent License Renewal Application Response to ONS SLRA 2nd Round RAI B4.1-3 (ADAMS Accession Numbers ML22110A207)
13. NRC E-mail dated March 16, 2022, Oconee SLRA – Request for Additional Information Set 4 (ADAMS Accession Numbers ML22080A077 and ML22080A079)

By letter dated June 7, 2021 (Reference 1), Duke Energy Carolinas, LLC (Duke Energy) submitted an application for the subsequent license renewal of Renewed Facility Operating License Numbers DPR-38, DPR-47, and DPR-55 for the Oconee Nuclear Station (ONS), Units 1, 2, and 3 to the U.S. Nuclear Regulatory Commission (NRC). On July 22, 2021 (Reference 2), the NRC determined that ONS subsequent license renewal application (SLRA) was acceptable and sufficient for docketing. In emails from Angela X. Wu (NRC) to Steve Snider (Duke Energy) dated September 22, 2021, November 23, 2021, January 11, 2022, January 18, 2022, and March 21, 2022 (References 3, 5, 7, 9, and 11), the NRC transmitted specific requests for additional information (RAI) to support completion of the Safety Review. The responses (References 4, 6, 8, 10, and 12) were provided to the NRC on October 22, 2021, January 7, 2022, February 14, 2022, February 21, 2022, and April 20, 2022.

In an email from Angela X. Wu (NRC) to Steve Snider (Duke Energy) dated March 16, 2022 (Reference 13), the NRC transmitted RAI Set 4 also to support completion of the Safety Review. This submittal provides those responses. As directed by the NRC Project Manager, the revised due date for this response is April 22, 2022

Enclosure 1 contains the responses to the RAIs for Set 4. SLRA changes are provided along with the affected SLRA section(s), SLRA page number(s), and SLRA mark-ups in each affected Enclosure 1 attachment. For clarity, deletions are indicated by strikethrough and inserted text by underlined red font.

Commitment 16 for the *Fire Water System* program is revised to address typographical and editorial errors.

Should you have any questions regarding this submittal, please contact Paul Guill at (704) 382-4753 or by email at paul.guill@duke-energy.com.

I declare under penalty of perjury that the foregoing is true and correct. Executed on April 22, 2022.

Sincerely,

Steven M. Snider

Site Vice President

Oconee Nuclear Station

Enclosure:

1. Responses to Requests for Additional Information Set 4

Attachment Number	RAI Number
1	B2.1.10-2a
2	B2.1.8-2a
3	B2.1.16-2a

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ENCLOSURE 1

OCONEE NUCLEAR STATION, UNITS 1, 2, AND 3
SUBSEQUENT LICENSE RENEWAL APPLICATION
RESPONSES TO REQUESTS FOR ADDITIONAL INFORMATION
SET 4

Enclosure 1
Responses to Requests for Additional Information Set 4

Requests for Additional Information (RAI) Attachments Index	
Attachment Number	**RAI Number**
1	B2.1.10-2a
2	B2.1.8-2a
3	B2.1.16-2a

ENCLOSURE 1

OCONEE NUCLEAR STATION, UNITS 1, 2, AND 3
SUBSEQUENT LICENSE RENEWAL APPLICATION
RESPONSES TO REQUESTS FOR ADDITIONAL INFORMATION
SET 4

ATTACHMENT 1
RAI B2.1.10-2a

Enclosure 1, Attachment 1

RAI B2.1.10-2a:

Regulatory Basis:

Section 54.21(a)(3) of Title 10 of the *Code of Federal Regulations* (10 CFR) requires an applicant to demonstrate that the effects of aging for each structure and component identified in 10 CFR 54.21(a)(1) will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. One of the findings that the U.S. Nuclear Regulatory Commission (NRC) staff must make to issue a renewed license (10 CFR 54.29(a)) is that actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under 10 CFR 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis. In order to complete its review and enable making a finding under 10 CFR 54.29(a), the staff requires additional information in regard to the matters described below.

Background:

The NRC staff made the following observations while reviewing Oconee Subsequent License Renewal Application (SLRA) Table 3.1.2-4 in the response to Request for Additional Information (RAI) B2.1.10-2, dated February 14, 2022:

1. SLRA Table 3.1.2-4, dated June 7, 2021 (ADAMS Package Accession No. ML21158A193), cited AMR item 3.4.1-014 for managing loss of material of the auxiliary feedwater nozzle inlet header exposed internally to treated water by the One-Time Inspection and Water Chemistry programs. While not shown as a change in the response to RAI B2.1.10-2, SLRA Table 3.1.2-4 now cites AMR item 3.1.1-014 for managing loss of material of the auxiliary feedwater nozzle inlet header exposed internally to treated water by the One-Time Inspection and Water Chemistry programs.

2. SLRA Supplement 1, dated October 28, 2021 (ADAMS Accession No. ML21302A208), revised SLRA Table 3.1.2-4 by adding Plant Specific Note 1 that states, “The environment of Treated Water is equal to the environment of Secondary Feedwater for the Tube Support Plate Assembly (support rods),” for managing loss of material of the tube support plate assembly (support rods) exposed externally to treated water by the Steam Generators and Water Chemistry programs (no GALL-SLR AMR item identified). The response to RAI B2.1.10-2 revised SLRA Table 3.1.2-4 by citing AMR item 3.1.1-071 (IV.D1.RP-226) and Industry Standard Note C for managing loss of material of the tube support plate assembly (support rods) exposed externally to treated water by the Steam Generators and Water Chemistry programs. SLRA Table 3.1.2-4 no longer cites Plant Specific Note 1 for managing loss of material of the tube support plate assembly (support rods) exposed externally to treated water by the Steam Generators and Water Chemistry programs.

   SLRA Table 3.1.1, dated June 7, 2021 (ADAMS Package Accession No. ML21158A193), states that AMR item 3.1.1-071 is “Not applicable to ONS steam generators. The associated NUREG-2191 aging items are not used.” However, SLRA Table 3.1.2-4 was revised in Supplement 3 dated December 15, 2021 (ADAMS Accession No. ML21349A005), and in the response to RAI B2.1.10-2 to cite AMR items 3.1.1-071 (IV.D1.RP-226) and 3.1.1-071 (IV.D1.RP-384). It does

not appear that SLRA Table 3.1.1 has been updated to reflect that AMR item 3.1.1-071 is now being used.

3. The response to RAI B2.1.10-2 revised SLRA Table 3.1.2-4 by citing Industry Standard Note C for AMR item 3.1.1-072 cited for managing loss of material of the steel tubesheet exposed externally to secondary feedwater by the Water Chemistry program. While not shown as a change in the response to RAI B2.1.10-2, SLRA Table 3.1.2-4 now states that the tubesheet material is stainless steel.

4. SLRA Supplement 3 dated December 15, 2021 (ADAMS Accession No. ML21349A005), revised SLRA Table 3.1.2-4 by citing AMR item 3.1.1-002 for managing cumulative fatigue damage of tube-to-tubesheet welds exposed externally to secondary feedwater. While not shown as a change in the response to RAI B2.1.10-2, SLRA Table 3.1.2-4 now does not cite AMR item 3.1.1-002 for managing cumulative fatigue damage of tube-to-tubesheet welds exposed externally to secondary feedwater.

Issue:

1. AMR item 3.1.1-014 in Volume 1 of NUREG-2191, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report” (ADAMS Accession No. ML17187A031), manages loss of fracture toughness due to neutron irradiation embrittlement by the Reactor Vessel Material Surveillance and Neutron Fluence Monitoring programs. Therefore, it is unclear to the staff why this AMR item is now cited for managing loss of material of the auxiliary feedwater nozzle inlet header exposed internally to treated water by the One-Time Inspection and Water Chemistry programs.

2. The environments for GALL-SLR AMR item 3.1.1-071 (IV.D1.RP-226) are secondary feedwater or steam. Therefore, it appears that Plant Specific Note 1 would still apply and may have been inadvertently deleted in the response to RAI B2.1.10-2. In addition, it appears that SLRA Table 3.1.1 has not been updated to reflect that AMR item 3.1.1- 071 is now being used.

3. The material for GALL-SLR AMR item 3.1.1-072 (IV.D2.RP-162) is steel. In addition, the staff’s understanding is that the tubesheets are steel with nickel alloy cladding. Therefore, it is unclear why SLRA Table 3.1.2-4 now states that the tubesheet material exposed externally to secondary feedwater is stainless steel.

4. AMR item 3.1.1-002 in the GALL-SLR Report (ADAMS Accession No. ML17187A031), manages cumulative fatigue damage of nickel alloy tubes and sleeves exposed to reactor coolant, secondary feedwater, and steam. Therefore, it appears that AMR item 3.1.1-002 would still apply and may have been inadvertently deleted in the response to RAI B2.1.10-2.

Request:

1. Discuss why AMR item 3.1.1-014 is cited for managing loss of material of the auxiliary feedwater nozzle inlet header exposed internally to treated water by the One-Time Inspection and Water Chemistry programs. Alternatively, revise SLRA Table 3.1.2-4 to cite the appropriate AMR item.

2. Discuss the removal of the citation to Plant Specific Note 1 for managing loss of material of the tube support plate assembly (support rods) exposed externally to treated water by the Steam Generators and Water Chemistry programs. Alternatively, revise SLRA Table 3.1.2-4 to cite Plant Specific Note 1.

3. Discuss changing the tubesheet material exposed externally to secondary feedwater from steel to stainless steel in SLRA Table 3.1.2-4. Alternatively, revise SLRA Table 3.1.2-4 to state that the tubesheet material exposed externally to secondary feedwater is steel.

4. Discuss removing the citation to AMR item 3.1.1-002 for managing cumulative fatigue damage of tube-to-tubesheet welds exposed externally to secondary feedwater. Alternatively, revise SLRA Table 3.1.2-4 to cite AMR item 3.1.1-002.

Response to RAI B2.1.10-2a:

Each of the issues discussed in this RAI identifies an inadvertent change to the SLRA tables in a previous RAI or SLRA supplement. The corrections are captured in the mark-ups below and represent the most up-to-date information for these entries. Duke Energy confirms, with the changes below, that SLRA Tables 3.1.1 and 3.1.2-4 are correct and current.

Request 1:

SLRA Table 3.1.2-4 has been revised to show SRP Item 3.4.1-014 for the loss of material line items.

Request 2:

The loss of material line items for the tube support plate assembly (support rods) exposed externally to treated water have been revised in SLRA Table 3.1.2-4 to reinstate Plant Specific Note 1.

Additionally, SLRA Table 3.1.1 has been revised to change SRP Item 3.1.1-071 to state, “Consistent with NUREG-2191, except that the associated NUREG-2191 item is aligned to stainless steel Babcock & Wilcox Once Through Steam Generator Tube Support Plate Assembly support rods and tube support plates.”

Request 3:

SLRA Table 3.1.2-4 has been revised to show the corrected material type of steel for the tubesheets exposed to secondary feedwater environment.

Request 4:

SLRA Table 3.1.2-4 has been revised to include the aging effect of cumulative fatigue damage for the tube-to-tubesheet welds exposed internally to secondary feedwater and to cite SRP Item 3.1.1-002.

SLRA Revisions:

SLRA Table 3.1.1 (page 3-65) is being revised as follows:

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-071	Steel, chrome plated steel, stainless steel, nickel alloy steam generator U-bend supports including antivibration bars exposed to secondary feedwater or steam	Cracking due to stress corrosion cracking or other mechanism(s); loss of material due general (steel only), pitting, crevice corrosion	AMP XI.M19, "Steam Generators," and AMP XI.M2, "Water Chemistry"	No	~~Not applicable to ONS steam generators. The associated NUREG-2191 aging items are not used.~~ **Consistent with NUREG-2191, except that the associated NUREG-2191 item is aligned to stainless steel Babcock & Wilcox Once Through Steam Generator Tube Support Plate Assembly support rods and tube support plates.**

SLRA Table 3.1.2-4 (page 3-194) is being revised as follows:

Table 3.1.2-4 Reactor Vessel, Reactor Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1	Notes
Auxiliary Feedwater Nozzle Inlet Header	Pressure Boundary	Steel	Air – Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S.29	3.4.1-034	A
			Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B2.1.4)	IV.D2.R-17	3.4.1-049	A
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	IV.D2.R-33	3.1.1-005	A, 3
				Loss of Material	One-Time Inspection (B2.1.20)	VIII.G.SP-74	~~3.1.1-014~~ **3.4.1-014**	A
					Water Chemistry (B2.1.2)	VIII.G.SP-74	~~3.1.1-014~~ **3.4.1-014**	A
				Wall Thinning	Flow-Accelerated Corrosion (B2.1.8)	IV.D2.R-38	3.1.1-061	A

SLRA Table 3.1.2-4 (page 3-202) is being revised as follows:

Table 3.1.2-4 Reactor Vessel, Reactor Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1	Notes
Tube Support Plate Assembly (support rods)	Structural Support	Stainless Steel	Secondary Feedwater (External)	Cracking	Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
			Treated Water (External)	Cumulative Fatigue Damage	TLAA	IV.C2.R-18	3.1.1-005	C, 1
			Treated Water (External)	Loss of Material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	C, 1
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C, 1

Oconee Nuclear Station, Units 1, 2, and 3
Subsequent License Renewal Application
Enclosure 1, Attachment 1

SLRA Table 3.1.2-4 (page 3-203) is being revised as follows:

Table 3.1.2-4 Reactor Vessel, Reactor Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1	Notes
Tubesheet	Pressure Boundary	~~Stainless~~ Steel	Secondary Feedwater (External)	Loss of Material	Steam Generators (B2.1.10)	IV.D2.RP-162	3.1.1-072	C
					Water Chemistry (B2.1.2)	IV.D2.RP-162	3.1.1-072	C
		Steel with Nickel Alloy Cladding	Air – Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B2.1.4)	IV.D2.R-17	3.1.1-049	A

Oconee Nuclear Station, Units 1, 2, and 3
Subsequent License Renewal Application
Enclosure 1, Attachment 1

SLRA Table 3.1.2-4 (page 3-204) is being revised as follows:

Table 3.1.2-4 Reactor Vessel, Reactor Internals, and Reactor Coolant System - Steam Generators - Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1	Notes
Tube-to-Tube Sheet Welds	Structural Support	Nickel Alloy	Reactor Coolant (External)	Cracking	Water Chemistry (B2.1.2)	IV.D2.RP-185	3.1.1-025	A
			Reactor Coolant (External)	Cracking	Steam Generators (B2.1.10)	IV.D2.RP-185	3.1.1-025	A
				Cumulative Fatigue Damage	TLAA	IV.D2.R-46	3.1.1-002	C
				Loss of Material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
			Secondary Feedwater (Internal)	Cracking	Steam Generators (B2.1.10)	IV.D2.R-47	3.1.1-069	C
					Water Chemistry (B2.1.2)	IV.D2.R-47	3.1.1-069	C
				Cumulative Fatigue Damage	**TLAA**	**IV.D2.R-46**	**3.1.1-002**	**A**
				Loss of Material	Steam Generators (B2.1.10)	IV.D2.RP-233	3.1.1-077	C

ENCLOSURE 1

OCONEE NUCLEAR STATION, UNITS 1, 2, AND 3
SUBSEQUENT LICENSE RENEWAL APPLICATION
RESPONSES TO REQUESTS FOR ADDITIONAL INFORMATION
SET 4

ATTACHMENT 2
RAI B2.1.8-2a

Enclosure 1, Attachment 2

RAI B2.1.8-2a:

Regulatory Basis:
Section 54.21(a)(3) of Title 10 of the *Code of Federal Regulations* (10 CFR) requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. One of the findings that the U.S. Nuclear Regulatory Commission (NRC) staff must make to issue a renewed license (10 CFR 54.29(a)) is that actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under 10 CFR 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis. In order to complete its review and enable making a finding under 10 CFR 54.29(a), the staff requires additional information in regard to the matters described below.

Background:
Aging Management Review (AMR) item 3.4.1-060 in Volume 1 of NUREG-2191, "Generic Aging Lessons Learned for subsequent License Renewal (GALL-SLR) Report" (ADAMS Accession No. ML17187A031), manages wall thinning due to erosion of metallic piping and piping components exposed to treated water by the Flow-Accelerated Corrosion (FAC) program.

Oconee Subsequent License Renewal Application (SLRA) Table 3.4.2-1, dated June 7, 2021 (ADAMS Package Accession No. ML21158A193), cites GALL-SLR AMR item 3.4.1-060 for managing wall thinning of stainless steel main condenser tubes exposed to treated water by the FAC program.

However, the response to Request for Additional Information (RAI) B2.1.8-2, dated February 14, 2022, states that "The ONS [Oconee Nuclear Station] Flow-Accelerated Corrosion AMP [Aging Management Program] is not designed to manage erosion of heat exchanger tubes."

Issue:
Even though the response to RAI B2.1.8-2 states that the ONS FAC program is not designed to manage wall thinning due to erosion of heat exchanger tubes, SLRA Table 3.4.2-1 cites GALL-SLR AMR item 3.4.1-060 for managing wall thinning of stainless steel main condenser tubes by the FAC program. It is unclear to the NRC staff if the ONS FAC program is designed to manage wall thinning due to erosion of main condenser tubes.

Request:
Discuss whether the ONS FAC program is designed to manage wall thinning due to erosion of main condenser tubes. If not, discuss which program will manage wall thinning due to erosion of the main condenser tubes and why the program is capable of managing wall thinning due to erosion of the main condenser tubes. In addition, revise SLRA Table 3.4.2-1, if appropriate.

Response to RAI B2.1.8-2a:

As reflected in the supplements below, the *Flow-Accelerated Corrosion* AMP does not manage wall thinning due to erosion of the main condenser tubes. Wall thinning due to erosion of the main condenser tubes is managed through existing periodic eddy current testing. The existing periodic eddy

current testing is credited by the *Open-Cycle Cooling Water System* AMP (B2.1.11) to manage age-related degradation of the main condenser tubing. The existing eddy current testing is capable of identifying age-related degradation across the full cross section of the main condenser tubing, including the raw water side (inner diameter) as well as the treated water side (outer diameter). Eddy current testing of ten percent of the main condenser tubes is performed every four years and relies on pre-established conservative tube plugging criteria to determine when corrective actions (i.e., plugging of affected tubes) is required. This approach is consistent with industry best practice as described in EPRI TR-3002020824, Main Condenser Integrity Assessment Guide and has been shown to be effective in preventing through wall leakage of condenser tubes and identifying both internal and external degradation of the main condenser tubes.

The SLRA is revised as shown in the attached supplement to indicate that wall thinning of the main condenser tubes is managed by the *Open-Cycle Cooling Water System* AMP (B2.1.11). Periodic eddy current testing of the main condenser tubes, implemented through the *Open-Cycle Cooling Water System* AMP (B2.1.11), provides reasonable assurance that intended functions are maintained consistent with the current licensing basis in the subsequent period of extended operation.

In addition, a typographical error associated with the numbering of plant specific notes in SLRA Table 3.4.2-1 (pages 3-1126, 3-1127, and 3-1144) is corrected in this response. SLRA Supplement 1 (ADAMS Accession Number ML21302A208), Attachments 18 and 19, added two plant specific notes to SLRA Table 3.4.2-1 and identified them both as ‘Note 4’.

Finally, a conforming change is made to the third paragraph of SLRA Appendix B, Section B2.1.8 (page B-82) to remove the treated borated water service environment. In accordance with the response to RAI B2.1.8-2 (ADAMS Accession Number ML22045A021), cavitation of High Pressure Injection system piping is not managed by the *Flow-Accelerated Corrosion* AMP and there are no other components within the scope of this AMP exposed to a treated borated water service environment.

SLRA Revisions:

SLRA Table 3.4.1 (page 3-1092) is revised as follows:

Table 3.4.1 Summary of Aging Management Programs for Steam And Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/ Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-060	Metallic piping, piping components exposed to steam, treated water	Wall thinning due to erosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191, **except that a different program is credited for the Main Condenser Tubes. The Open-Cycle Cooling Water System (B2.1.11) program is credited for managing wall thinning for the Main Condenser Tubes.**

SLRA Table 3.4.2-1 (page 3-1120) is revised as follows:

Table 3.4.2-1 Steam and Power Conversion Systems - Condensate System - Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1	Notes
Main Condenser Tubes	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material, Flow Blockage	Open-Cycle Cooling Water System (B2.1.11)	VIII.E.SP-117	3.4.1- 019	B
			Treated Water (External)	Loss of Material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1- 085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1- 085	A
				Wall Thinning	~~Flow Accelerated Corrosion (B2.1.8)~~ **Open-Cycle Cooling Water System (B2.1.11)**	VIII.D1.S-408	3.4.1- 060	~~C~~ **E, 6**

SLRA Table 3.4.2-1 (pages 3-1126 and 3-1127) is revised as follows:

Table 3.4.2-1 Steam and Power Conversion Systems - Condensate System - Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1	Notes
Piping and Piping Components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B2.1.8))	VIII.D1.S-408	3.4.1- 060	A, 3
			Treated Water >60°C (140° (Internal)	Cumulative Fatigue Damage	TLAA	VII.E1.A-57	3.3.1- 002	A, 3
		Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B2.1.8))	VIII.D1.S-16	3.4.1-005	A, 3, 4 5
						VIII.D1.S-408	3.4.1-060	A, 3, 4 5
			Treated Water >60°C (140° (Internal)	Cumulative Fatigue Damage	TLAA	VIII.D1.S-11	3.4.1- 001	A, 3
	Structural Integrity	Stainless Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B2.1.8))	VIII.D1.S-408	3.4.1- 060	A, 3
			Treated Water >60°C (140° (Internal)	Cumulative Fatigue Damage	TLAA	VII.E1.A-57	3.3.1- 002	A, 3
		Steel	Treated Water (Internal)	Wall Thinning	Flow-Accelerated Corrosion (B2.1.8))	VIII.D1.S-16	3.4.1-005	A, 3, 4 5
						VIII.D1.S-408	3.4.1-060	A, 3, 4 5
			Treated Water >60°C (140° (Internal)	Cumulative Fatigue Damage	TLAA	VIII.D1.S-11	3.4.1- 001	A, 3

SLRA Table 3.4.2-1 (page 3-1144) is revised as follows:

Plant Specific Notes:

4. Components constructed of Copper Alloy and Copper Alloy >15% Zn share common aging effects. For Copper Alloy >15% Zn components, these common aging effects are managed by aligning to a GALL SLR item for Copper Alloy as a direct match. Unique aging effects applicable only to components constructed of Copper Alloy >15% Zn, are managed by aligning to a GALL SLR line item specific to Copper Alloy >15% Zn.

~~4~~ **5.** Steel “Piping and Piping Components” that are susceptible to wall thinning (due to erosion or flow accelerated corrosion) includes components constructed of carbon steel and gray cast iron.

6. The *Open-Cycle Cooling Water System* AMP is credited for managing wall thinning on the treated water (exterior) side of the Main Condenser Tubes by means of eddy current testing performed from the interior (raw water side) of the tubes.

SLRA Appendix B2.1.8 (page B-82) is revised as follows:

B2.1.8 FLOW-ACCELERATED CORROSION

Program Description

The program also manages wall thinning caused by mechanisms other than flow-accelerated corrosion in copper alloy, steel and stainless steel piping and piping components exposed to treated water ~~and treated borated water environments~~ in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanisms.

SLRA Appendix B2.1.8 (page B-84) is revised as follows:

B2.1.8 FLOW-ACCELERATED CORROSION

Operating Experience

3. **Not used.** ~~In May 2016 several condenser tubes were identified to have experienced erosion on the tube outer diameter in the Oconee Unit 3 main condenser and there was concern the tubes may erode to the point portions of the tubes may become loose parts in the condenser. The issue was entered into the corrective action program for evaluation of the potentially adverse condition. The tubes identified as having erosion, the 1st and 2nd outermost rows of tubes, had previously been plugged based upon eddy current test results and were no longer in service.~~

   ~~A walkdown inside the condenser was executed to perform a close up visual inspection of the tubes that exhibited indications of external erosion. Additionally, eroded tubes were physically checked by grasping the tube and shaking to validate the tubes had rigidity and structural integrity. An engineering evaluation determined no tubes should be removed based on the visual and hands on inspection. It was also observed that the presence of out of service tubes along the periphery of tube bundles provides a level of protection to the in service tubes from steam erosion and potential impacts from foreign material intrusion.~~

   ~~Condenser tubes that remain in service will continue to be periodically eddy current tested for integrity and plugged when determined by an engineering evaluation. Out of service condenser tubes will be visually inspected periodically and evaluated for removal when erosion is identified.~~

   ~~OE example 3 provides objective evidence that program inspections will effectively monitor in-scope SSCs to ensure that these components will continue to perform their intended functions, and that appropriate aging management will be performed during the SPEO. This OE also demonstrates the effectiveness of the corrective action program to identify and evaluate adverse conditions, and to drive appropriate enhancements in station programs and procedures.~~

SLRA Appendix B2.1.11 (page B-99) is revised as follows:

B2.1.11 OPEN-CYCLE COOLING WATER SYSTEM

Program Description

The program manages piping, piping components, and heat exchanger components in safety related and non-safety related raw water systems that are exposed to a raw water environment for loss of material, cracking, reduction of heat transfer, and flow blockage. Wall thinning of the exterior (closed-cycle cooling water) side of the RCW Heat Exchanger tubes **and the exterior (treated water) side of the Main Condenser tubes** is also managed by the *Open-Cycle Cooling Water System* program. Eddy current testing is credited for managing wall thinning on the ~~closed-cycle cooling water (~~exterior~~)~~ side of the RCW Heat Exchanger **and Main Condenser** tubes. The program also manages loss of coating integrity for certain components that do not perform a pressure boundary intended function and where loss of coating integrity would not impact the intended functions of downstream components. System and component testing, flushing, visual inspections, and nondestructive examination are conducted to ensure that identified aging effects are managed such that system and component intended functions and integrity are maintained.

SLRA Appendix B2.1.11 (page B-106) is revised as follows:

B2.1.11 OPEN-CYCLE COOLING WATER SYSTEM

Operating Experience

5. In May 2016 several condenser tubes were identified to have experienced erosion on the tube outer diameter in the Oconee Unit 3 main condenser and there was concern the tubes may erode to the point portions of the tubes may become loose parts in the condenser. The issue was entered into the corrective action program for evaluation of the potentially adverse condition. The tubes identified as having erosion, the 1st and 2nd outermost rows of tubes, had previously been plugged based upon eddy-current test results and were no longer in service.

A walkdown inside the condenser was executed to perform a close up visual inspection of the tubes that exhibited indications of external erosion. Additionally, eroded tubes were physically checked by grasping the tube and shaking to validate the tubes had rigidity and structural integrity. An engineering evaluation determined no tubes should be removed based on the visual and hands on inspection. It was also observed that the presence of out of service tubes along the periphery of tube bundles provides a level of protection to the in service tubes from steam erosion and potential impacts from foreign material intrusion.

Condenser tubes that remain in service will continue to be periodically eddy-current tested for integrity and plugged when determined by an engineering evaluation. Out of service condenser tubes will be visually inspected periodically and evaluated for removal when erosion is identified.

OE example 5 provides objective evidence that program inspections will effectively monitor in-scope SSCs to ensure that these components will continue to perform their intended functions, and that appropriate aging management will be performed during the SPEO. This OE also demonstrates the effectiveness of the corrective action program to identify and evaluate adverse conditions, and to drive appropriate enhancements in station programs and procedures.

ENCLOSURE 1

OCONEE NUCLEAR STATION, UNITS 1, 2, AND 3
SUBSEQUENT LICENSE RENEWAL APPLICATION
RESPONSES TO REQUESTS FOR ADDITIONAL INFORMATION
SET 4

ATTACHMENT 3
RAI B2.1.16-2a

Enclosure 1, Attachment 3

RAI B2.1.16-2a:

Regulatory Basis:
Section 54.21(a)(3) of Title 10 of the *Code of Federal Regulations* (10 CFR) requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. One of the findings that the U.S. Nuclear Regulatory Commission (NRC) staff must make to issue a renewed license (10 CFR 54.29(a)) is that actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under 10 CFR 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis. In order to complete its review and enable making a finding under 10 CFR 54.29(a), the staff requires additional information in regard to the matters described below.

Background:
Oconee Subsequent License Renewal Application (SLRA) Supplement 2, dated November 11, 2021 (ADAMS Accession No. ML21315A012), revised SLRA Section B2.1.16 and SLRA Table A6.0-1 by revising Enhancements 3, 6, and 9 to the Fire Water System program. In addition, SLRA Supplement 2 revised the implementation schedule for the Fire Water System program in SLRA Table A6.0-1.

In response to Request for Additional Information (RAI) B2.1.16-2, dated February 14, 2022, the applicant revised Enhancement 5 to the Fire Water System program, including the related commitment in SLRA Table A6.0-1. However, the NRC staff noted that the changes to Enhancement 6 and the implementation schedule for the Fire Water System program made in SLRA Supplement 2 do not appear in SLRA Table A6.0-1 in the response to RAI B2.1.16-2.

Issue:
The NRC staff has concerns regarding whether previous changes to SLRA Table A6.0-1 are still in effect because the latest version of SLRA Table A6.0-1 in the response to RAI B2.1.16-2 does not include previous changes to the table for the Fire Water System program.

Request:
Discuss the apparent omission of the changes to Enhancement 6 and to the implementation schedule for the Fire Water System program (made in SLRA Supplement 2) from the recent response to RAI B2.1.16-2. Include information for how changes to the commitment table (and specifically the implementation schedule) are being tracked to ensure appropriate version control. In addition, confirm that previous changes made to the Fire Water System program that are not reflected in the latest version of SLRA Table A6.0-1 are still in effect and provide SLRA Table A6.0-1 in its latest form.

Response to RAI B2.1.16-2a:

The changes made to the SLRA Table A6.0-1 entries for the *Fire Water System* program which were submitted prior to the response to RAI B2.1.16-2 (ADAMS Accession Number ML22045A021) remain in effect and were not intended to be omitted by the response to RAI B2.1.16-2 (ADAMS Accession Number ML22045A021). Specifically, as related to this RAI B2.1.16-2a, the changes made to enhancement 6 and the implementation schedule of the *Fire Water System* program remain as stated in the Supplement 2 (ADAMS Accession Number ML21315A012) submittal.

Each individual change to the commitment table, including the implementation schedule, is tracked separately during the NRC review process. At the conclusion of the NRC review, all changes made during the application review process will be integrated into a final version (consistent with the staff's final version in the SER) to be included in the ONS UFSAR in accordance with the anticipated license condition of the subsequent renewed facility operating licenses.

SLRA Table A6.0-1, Item #16 for the *Fire Water System* program is provided in its latest form below, with all changes made by previous submittals incorporated, including: SLRA Supplement 1 (ADAMS Accession Number ML21302A208) which added enhancement 11; SLRA Supplement 2 (ADAMS Accession Number ML21315A012) which revised enhancements 3, 6, and 9 and the implementation schedule; and RAI B2.1.16-2 (ADAMS Accession Number ML22045A021) which revised enhancement 5. No new technical changes to SLRA Table A6.0-1 are made as a result of this response to RAI B2.1.16-2a. Two newly identified editorial changes have been made to enhancement 9, as indicated below.

SLRA Revisions:

The consolidated and editorial changes to SLRA Table A6.0-1, #16 (pages A-82, A-83, and A-84) are provided below:

Table A6.0-1: Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	The *Fire Water System* AMP is an existing program that will be enhanced to: 1. Perform internal visual inspections of deluge system piping by removing a hydraulically remote nozzle to identify internal corrosion, foreign material, and obstructions to flow. Internal visual inspections will be performed in 50 percent of the deluge systems within the scope of the *Fire Water System* AMP that are not subject to flow testing every five years. During the subsequent five year inspection period, the alternate systems will be inspected such that piping in 100 percent of the deluge systems within the scope of the program is inspected every ten years. Follow-up volumetric wall thickness examinations will be performed if internal visual inspections detect an unexpected level of degradation due to corrosion and corrosion product deposition. 2. Prior to 50 years in service, sprinkler heads will be submitted for field-service testing by a recognized testing laboratory consistent with NFPA 25, 2011 Edition, Section 5.3.1. 3. Perform a one-time volumetric wall thickness inspection on a representative sample of deluge	B2.1.16	Program will be implemented and inspections or tests will begin 5 years prior to the SPEO. Inspections or tests that are to be completed prior to the SPEO will be completed 6 months prior to the SPEO or no later than the last refueling outage prior to the SPEO.

#	Program	Commitment	AMP	Implementation
		system supply piping that is periodically subjected to flow during functional testing. The representative sample will be based on the population of deluge system piping that is periodically subject to flow but is normally dry. The one-time volumetric wall thickness inspection activity will include criteria for selection of inspection locations, acceptance criteria, and will specify the need for follow-up examinations based on inspection results. 4. Perform an obstruction investigation in accordance with NFPA 25, 2011 Edition, Section 14.3 if evidence of unacceptable internal flow blockage that could result in failure of system function is identified during internal inspections. When unacceptable internal flow blockage is detected, corrective actions will include removal of the material, an extent of condition determination, review for increased inspections, follow-up examinations, and a flush in accordance with NFPA 25 Annex D.5, *Flushing Procedures*. 5. Revise inspection procedures to include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes and to provide specific guidance for the identification and documentation of indications of age-related degradation. For internal surfaces this includes indications of corrosion such as surface irregularities and signs of fouling which could lead to flow blockage. For external surfaces age-related degradation includes indications of corrosion beyond minor surface rusting and signs of current or past leakage. 6. Perform flow testing of at least one hose station in each building every five years to demonstrate the capability to provide the design pressure at required flow. Flow testing will be performed at the hydraulically most remote hose station. If acceptance criteria are not met, at least two additional tests shall be performed within five years. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests. The		

#	Program	Commitment	AMP	Implementation
		additional tests include at least one test at one of the other units with the same material, environment, and aging effect combination. 7. Perform external visual inspections of the elevated water storage tank in accordance with Section 9.2.5.5 of NFPA 25, 2011 Edition at least once every two years. 8. Perform flushing of the mainline strainers following system actuation in accordance with Section 10.2.7 of NFPA 25, 2011 Edition. 9. Perform main drain testing of the deluge system risers at ~~last~~ **least** once every two years. Main drain testing of deluge systems will be performed in accordance with the procedure described **in** Sections 13.2.5 and A.13.2.5 of NFPA 25, 2011 Edition. When there is a ten percent reduction in full flow pressure when compared to an established baseline value, the cause of the reduction shall be identified and corrected if necessary. If acceptance criteria are not met, at least two additional tests shall be performed within two years. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests. The additional tests include at least one test at one of the other units with the same material, environment, and aging effect combination. 10. Acceptance criteria and corrective actions for internal inspections of the elevated water storage tank will be in accordance with the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers and Tanks* program. Tank wall thickness measurements will be conducted if interior pitting or general corrosion (beyond minor surface rust) is detected. 11. Personnel involved with inspection of the internal coatings of the elevated water storage tank and evaluation of degraded conditions will be trained and qualified in accordance with an ASTM international standard endorsed in Regulatory Guide 1.54, including NRC staff limitations associated with a particular standard.		