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SUBJECT: Forwards response to requests for addl info re license renewal for Oconee Nuclear Station,Units 1,2 & 3.Util responses provided in six attachments to ltr.Attachment 1

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February 17, 1999

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U. S. Nuclear Regulatory Commission
Washington, DC 20555

Subject: License Renewal
Response to Requests for Additional Information
Oconee Nuclear Station
Docket Nos. 50-269, -270, -287

By letter dated July 6, 1998, Duke Energy Corporation submitted an Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3 (Application). Exhibit A of the Application contains the technical information required by 10 CFR Part 54. The NRC staff is reviewing the information provided by Duke Energy in the Application and by several letters identified areas where additional information is needed to complete its review. Duke responses are provided in six attachments to this letter.

Attachment 1 contains our responses to staff requests for additional information (RAIs) concerning the Reactor Coolant System review of Oconee contained in the following sections of Exhibit A of the Application: 1.5.5, 2.4, 3.4, 3.5.5, 4.3.1, 4.3.7, 4.5, 4.10, 4.18, 4.22, 4.26, 5.1, 5.4.1, and 5.4.2. In additional, responses to the following General RAIs are provided: G-2, G-4, G-6, G-7, G-8 and G-9. Some of these responses contain new commitments or modify commitments previously made in the Application. These commitments are restated in Attachment 7 to facilitate tracking and management.

Attachment 2 contains our responses to staff RAIs concerning the mechanical integrated plant assessment of Oconee contained in the following sections of Exhibit A of the Application: 2.2, 2.5, 3.5, 4.3.13, 4.16, 4.17, and 4.25. None of these responses contains any new commitments.

Attachment 3 contains our responses to staff RAIs concerning the electrical integrated plant assessment of Oconee contained in the following sections of Exhibit A of the Application: 2.6, 3.2, and 3.6. None of these responses contains any new commitments.

Attachment 4 concerns the topic of "consumables" and contains our responses to the following staff RAIs: 1.5.2-1, 2.2-5, 2.4-4, 2.5.8-4, 2.7-1, 3.3-19, 3.7.1-1, 3.7.3-4, 3.7.3-8, 3.7.5-2, 3.7.6-3, 3.7.6-6, 3.7.7-3, and 3.7.9-2. None of these responses contains any new commitments.

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Attachment 5 concerns the topic of "inaccessible areas" and contains our responses to the following staff RAIs: G-3, G-5, 3.3-21, 3.5.8-7, 3.7.3-7, 3.7.5-3, 3.7.6-5, 3.7.7-5, and 4.18-2. None of these responses contains any new commitments.

Attachment 6 contains our responses to staff RAIs 2-1, G-1 and 4.13-1. None of these responses contains any new commitments.

If there are any questions, please contact Bob Gill at 704-382-3339.

Very Truly Yours,

W. R. McCollum Jr., Site Vice President
Oconee Nuclear Station

W. R. McCollum Jr., being duly sworn, states that he is Vice President, Oconee Nuclear Station, Duke Energy Corporation, that he is authorized on the part of said Company to sign and file with the U. S. Nuclear Regulatory Commission these responses to NRC requests for additional information concerning the Application to Renew the Facility Operating Licenses of Oconee Nuclear Station submitted by letter dated July 6, 1998; and that all statements and matters set forth herein are true and correct to the best of his knowledge and belief. To the extent that these statements are not based on his personal knowledge, they are based on information provided by Duke employees and/or consultants. Such information has been reviewed in accordance with Duke Energy Corporation practice and is believed to be reliable.

W. R. McCollum, Jr., Vice president
Oconee Nuclear Site

Subscribed and sworn to before me this 17th day of February 1999.

Notary Public

My Commission Expires:

2-12-2003

xc: (w/ Attachments)

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50-269 DE OCONEE 1

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION RE RENEWED OL APPL.

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ATTACHMENT 1
Oconee Nuclear Station
Application for Renewed Operating Licenses
Responses to NRC Requests for Additional Information (RAI)

Set # 04
February 17, 1999

Set # 04
February 17, 1999

RAI 1.5.5-1 (11/24/98A)
Section 1.5.5.3 of the license renewal application indicates that additional confirmatory research is ongoing at Oconee in support of the generic resolution of issues associated with Generic Safety Issue (GSI) 190, "Fatigue Evaluation of Metal Components for 60-year Plant Life." The application further indicates that the Oconee study will apply the methodology developed in EPRI Report TR-105759, "An Environmental Factor Approach to Account for Reactor Water Effects in Light Water Reactor Pressure Vessel and Piping Fatigue Evaluations." Application of this methodology was discussed during a March 19, 1998, meeting between the industry and the staff. A letter from Christopher Grimes to NEI dated November 2, 1998, titled "Request for Additional Information on the Industry's Evaluation of Fatigue Effects for License Renewal", summarizes the staff's technical concerns regarding the methodology in EPRI Report TR-105759. Upon resolution of these concerns and when a final determination regarding GSI-190 has been made, you will be expected to address any particular action that may arise as a result of such determination.

Since the conclusion regarding GSI-190 in Section 1.5.5.4 of your application for license renewal relies on the conclusions from the referenced EPRI report, discuss how Oconee meets the relevant portion of Section 54.29 of the license renewal rule as discussed in the statement of considerations (SOC) (60 FR 22484, May 1995) in the absence of the staff's endorsement of EPRI Report TR-105759. Although the staff expects timely resolution of GSI-190, your response should address the situation in which GSI-190 is not resolved prior to the current license term. Consistent with the SOC, it is expected that Duke will "submit a technical rationale which demonstrates that the CLB [current licensing basics] will be maintained until some later point in time in the period of extended operation, at which time one or more reasonable options (e.g., replacement, analytical evaluation, or a surveillance/maintenance program) would be available to adequately manage the effects of aging...and briefly describe options that are technically feasible during the period of extended operation to manage the effects of aging...."

Response to RAI 1.5.5-1
To put the response to RAI 1.5.5-1 in perspective, it is important to realize that the Application divides the topic of thermal fatigue into two issues: (1) the current thermal fatigue design and licensing basis and (2) the interpretation of the residual research related to GSI-190. Each of these issues is addressed separately in the Application.

The current thermal fatigue design and licensing bases of various Oconee mechanical components falling within the scope of license renewal are formed by a set of analyses that are based in ASME Section III and USAS B31.7 Class I design rules. These code design rules require the assumption of various numbers of thermal operating cycles over the lifetime

of the component as a part of the component stress analysis. Because of these thermal cycle count assumptions, the analyses are considered to be time-limited aging analyses (TLAA). Management of these thermal cycle count assumptions is addressed in Section 5.4.1 of Exhibit A of the Application.

As described in Section 5.4.1.1 of the Application, the review of these thermal cycle count assumptions first involved determining actual accumulated thermal cycles in order to determine where the component was in its fatigue lifetime. Next, a conservative cycle count accumulation rate was used to project when plant operation would exceed the assumed number of design cycles. This activity served to determine components that may require more specific thermal fatigue management attention. Finally, with this understanding, the thermal cycle count assumptions for all applicable components are being and will continue to be managed by the Oconee Thermal Fatigue Management Program which is described in Section 5.4.1.3. Under this program, if a thermal cycle assumption limit is approached, corrective actions include the options of component reanalysis and replacement.

The residual research aspects of GSI-190 are addressed, in part, in Section 1.5.5 of Exhibit A of the Application. The underlying concern in GSI-190 is that the basis of the code design rules, such as those used for establishing the Oconee thermal fatigue design and licensing basis, may not be conservative in some instances. The information provided in Section 1.5.5 of the Application was based on industry generic calculations using the (then) current state of the research. The discussion reported the industry generic technical rationale for concluding that the effects of thermal fatigue are adequately enveloped by the current code design rules. This discussion was provided in order to address this issue with respect to operation of Oconee during the period of extended operation pending generic resolution of GSI-190.

Duke understands the staff has concerns with the generic approach taken in EPRI Report TR-105759 as articulated in their November 2, 1998 letter referred to in RAI 1.5.5-1. These concerns can certainly influence and even redirect the Oconee confirmatory research being carried out by Duke and EPRI as described in Section 1.5.5.3. Duke did not intend to use Section 1.5.5 to conclude that GSI-190 should be resolved as implied in this RAI. Instead, Duke intended to address GSI-190 and the (then) current state of the research in order to support the rationale that the effects of thermal fatigue will be adequately managed for the extended period of operation by the programmatic oversight described under issue (1) or until GSI-190 is resolved.

Eventually, the research activities will be completed and the NRC staff will resolve GSI-190. The resolution of GSI-190 by the staff can result in either no new requirements or the establishment of new regulatory requirements. If the staff determines that no new

requirements are justified, then the resolution of GSI-190 will have no effect on how Oconee will manage thermal fatigue during the period of extended operation. Alternatively, if new requirements are imposed by the NRC, then Duke will comply with these new requirements. The new requirements may lead to action such as design reanalysis, hardware replacement or enhanced surveillance monitoring of any affected hardware locations. Because the improvements that would result from the new requirements will be enhancements to the existing Oconee Thermal Fatigue Management Program, they can be implemented by Oconee after the start of the extended period of operation, if needed.

The two issues associated with the topic of thermal fatigue must be viewed separately. The residual research concerns of GSI-190 are not directly related to the Oconee thermal fatigue design and licensing basis, but instead are related to the code design rules from which this basis is derived. This is an important distinction. The information offered in Section 5.4.1 of the Application is the technical rationale for concluding that the effects of thermal fatigue will be adequately managed for the extended period or until the resolution of GSI-190 becomes available. The requirements within the relevant portions of §54.29 of the license renewal rule as discussed in the statement of considerations (60 FR 22848, May 1995) are met by the ongoing Oconee Thermal Fatigue Management Program.

RAI 2.4-2 (11/30/98C)
Page 4-51, Section 4.5.1.3.1, Oconee Updated Final Safety Analysis Report (UFSAR) [updated December 31, 1997], indicates that lifting lugs are provided for remote handling of the plenum assembly (Reactor Vessel Internals). These lifting lugs are welded to the cover grid. It was not clear from the submittal (Fig. 2.4-5) if these lifting lugs and attachment welds are within the scope of license renewal. Discuss whether these items are within the scope of license renewal or provide a basis for their exclusion.

Response to RAI 2.4-2
The lifting lugs are within the scope of license renewal and are described in the B&W Owners Group Reactor Vessel Internals Report, BAW-2248, Section 2.1.1, Page 2-5, which has been incorporated by reference into Exhibit A of the Application. As described in Section 2.4.6 of Exhibit A of the Application, the current design of the Oconee reactor vessel internals was reviewed and determined that they are bounded by the description of items subject to aging management review in BAW-2248, with exception of the thermal shield and the thermal shield upper restraint.

RAI 2.4-3 (11/30/98C)
Page 5-44, Section 5.3.1, UFSAR [updated December 31, 1997], indicates that guide lugs are welded inside the reactor vessel's lower head which limit a vertical drop of the reactor internals and core to ½ inch or less and prevent rotation about the vertical axis in the unlikely event of a major internals component failure. It was not clear from the submittal (Figs. 2.4-2, 3 and 4) if these lugs and attachment welds are within the scope of license renewal. Discuss whether these items are within the scope of license renewal or provide a basis for their exclusion.

Response to RAI 2.4-3
The core guide lugs and their attachment welds are within the scope of license renewal and are described in the B&W Owners Group Reactor Vessel Report, BAW-2251, Section 2.3, Page 2-7, which is incorporated by reference into the Application. As described in Section 2.4.5 of Exhibit A of the Application, the current design of the Oconee reactor vessel was reviewed and determined that the Oconee reactor vessels are bounded by the description of items subject to aging management review in BAW-2251.

RAI 2.4-5 (11 /30/98C)
Page 5-43, Section 5.3.1, UFSAR [updated December 31, 1997], indicates that test taps are provided in the annulus between the two O-rings to afford a means to leak test the vessel closure seal. It was not clear from the submittal (Figs. 2.4-2, 3, and 4) if these test taps are within the scope of license renewal. Discuss whether these items are within the scope of license renewal or provide a basis for their exclusion.

Response to RAI 2.4-5
The test taps (a.k.a., monitoring pipes) are discussed in the B&W Owners Group Reactor Vessel Report, BAW-2251, Section 2.5.2, Page 2-9, which is incorporated by reference into Exhibit A of the Application. The monitoring pipes do not support a reactor vessel intended function and are not subject to aging management review. NRC concurrence regarding elimination of the monitoring pipes from the scope of aging management review may be found in Section 3.1.2.5.1.2 of the NRC's Draft Safety Evaluation regarding the B&WOG reactor vessel report, BAW-2251 [NRC letter from C.I. Grimes to D. J. Firth, dated September 18, 1998, entitled "Draft Safety Evaluation Concerning the B&WOG Generic License Renewal Topical report entitled, Demonstration of the Management of Aging Effects for the Reactor Vessel, BAW-2251, June 1996."].

RAI 2.4-6 (11 /30/98C)
Figures 2.4-2, 3 and 4 of the submittal show the reactor vessel. However, these figures do not show the closure head of the vessel. The following two questions are relevant to the vessel head:

(1) The lifting lugs, which are used to lift the vessel head are welded to it. Please indicate if these lifting lugs and attachment welds are included within the scope of license renewal. If so, provide a cross reference to where these are addressed in the submittal. If not, provide the basis for their exclusion.

(2) In response to the Three Mile Island Lessons Learned Report, NUREG-0737, Item II.B.I, vents were to be added to the reactor vessel and to the pressurizer head. One of the intended functions of the vents is to ensure core cooling during loss-of-coolant accident. Please indicate if these vent systems are within the scope of license renewal. If so, provide a cross reference to where these items are discussed in the submittal. If not, provide the basis for their exclusion.

Response to RAI 2.4-6

(1) Lifting Lugs

The reactor vessel lifting lugs are discussed in the B&W Owners Group Reactor Vessel Report, BAW-2251, Section 2.5.3, Page 2-9, which is incorporated by reference into Exhibit A of the Application. The RV lifting lugs do not support a reactor vessel intended function and are not subject to aging management review. NRC concurrence regarding elimination of the lifting lugs from the scope of aging management review may be found in Section 3.1.2.5.1.3 of the NRC's Draft Safety Evaluation regarding the B&WOG reactor vessel report, BAW-2251 [NRC letter from C. I. Grimes to D. J. Firth, dated September 18, 1998, entitled "Draft Safety Evaluation Concerning the B&WOG Generic License Renewal Topical report entitled, Demonstration of the Management of Aging Effects for the Reactor Vessel, BAW-2251, June 1996."].

(2) Reactor Vessel and Pressurizer Vent Lines

The reactor vessel head vent line is within the scope of license renewal and the Class 1 portion of the reactor vessel head vent line is described in the B&W Owners Group Reactor Coolant System Piping Report, BAW-2243A, Section 2.1.6, Page 2-17, which is incorporated by reference into Exhibit A of the Application. As described in Section 2.4.5 of Exhibit A of the Application, a review of Oconee-specific design information confirmed that the configuration of the vent line described in BAW-2243A is accurate. Reactor Coolant System vents, drains, and instrument lines are addressed in Section 2.5.12 of Exhibit A of the Application. The non-Class 1 portion of the reactor vessel head vent line is shown on drawings OLRFD – 100A – 1.1, - 2.1, - 3.1 which are listed in Table 2.5-20 of Exhibit A of the Application. (Reactor Coolant System hot leg vents were also installed at Oconee in response to Item III.B.1 of NUREG-0737 and are also shown on these drawings.)

The pressurizer vent line is within the scope of license renewal and the Class 1 portion of the vent line is described in the BAW-2243A, Section 3.1.3.1, Page 2-15. As described in Section 2.4.3 of Exhibit A of the Application, a review of Oconee-specific design information confirmed that the configuration of the vent line described in BAW-2243A is accurate. Reactor Coolant System vents, drains, and instrument lines are addressed in Section 2.5.12 of Exhibit A of the Application. The non-Class 1 portion of the pressurizer vent line is shown on drawings OLRFD – 100A – 1.2, - 2.2, - 3.2 which are listed in Table 2.5-20 of Exhibit A of the Application.

RAI 2.4-7 (11 /30/98C)
Table 2.4-4 of the submittal lists RCS components and their intended functions. Discuss why the following intended functions, for the specified components, were not considered as intended functions to be maintained for license renewal. Provide bases for your determinations. The components and their intended functions are given below:

Component	Intended Function(s)
Reactor Vessel Internals	Capability to shutdown the reactor and maintain it in a safe shutdown condition.
Once Through Steam Generator	Provide heat removal under abnormal operating conditions.

Additionally, verify that reactor coolant pumps do not have any intended functions credited for design basis events that meet the requirements of 10 CFR 54.4, other than the intended function cited for license renewal, i.e., pressure boundary function of the pump casing and flow-related coastdown function associated with the RCP flywheel, and are therefore not considered within the scope.

Response to RAI 2.4-7
Reactor Vessel Internals Intended Function—capability to shutdown the reactor
As described in the B&W Owners Group response to Open Item 1 in the Draft Safety Evaluation regarding the Reactor Vessel Report, BAW-2251 [FTI letter from David J. Firth to Jack W. Roe, OG-1725, October 30, 1998, B&WOG Generic License Renewal Program Topical Report BAW-2251], "Demonstration of the Management of Aging Effects for the Reactor Vessel," Responses to Open Items in Draft Safety Evaluation, the capability to shutdown the reactor is defined by Duke as a system level scoping function and is not a component intended function. The addition of this function as an intended function would not add any reactor vessel internals items as subject to aging management review.

Once Through Steam Generator (OTSG) Intended Function—provide heat removal under abnormal operating conditions
The OTSG intended functions listed in Table 2.4-4, Page 2.4-32, of Exhibit A of the Application include (1) maintain the primary pressure boundary so the Reactor Coolant System can perform its system functions, and (2) provide decay heat removal under design basis conditions. The second Oconee OTSG intended function encompasses the NRC specified function of provide heat removal under abnormal operating conditions. Design basis conditions include all modes of operation: i.e., normal, upset, emergency, and faulted.

Reactor Coolant Pump Intended Function
The Oconee UFSAR and Reactor Coolant System Design Basis Document were reviewed and the only intended function of the RCP is the pressure boundary function listed in Table 2.4-4 of OLRP-1001; no additional intended functions were identified for the reactor coolant pumps. The coastdown function of the reactor coolant pump is required to mitigate selected design basis events (e.g., loss of coolant flow accident in Chapter 15 of the UFSAR); however, Oconee determined that flow coastdown, which is a function of system resistance and flywheel inertia, is a system level function and not a component function. The rotating parts of the reactor coolant pump are not subject to aging management review in accordance with §54.21 (a)(1)(i), as specified in Section 2.4.8 of Exhibit A of the Application. The time-limited aging analysis of the reactor coolant pump flywheel is addressed in Section 5.4.4 of Exhibit A of the Application.

RAI 3.4.3-1 (12/2/98D)
Section 3.4.3 of the license renewal application references report BAW-2243A. Section 3.4.4 references BAW-2244A. These reports do not address specific time limited aging analyses for the reactor coolant system piping or for the pressurizer. It is left up to the individual plant to address this issue. Therefore, for Oconee Units 1, 2, and 3, we request that you provide a demonstration that the ASME Code Section III cumulative usage factor for all Reactor Coolant System Piping and Pressurizer Class 1 components will be less than or equal to 1.0 for 60 years of plant operation.

Response to RAI 3.4.3-1
A demonstration that cumulative usage factors for the reactor coolant system piping are acceptable for the period of extended operation is contained in Section 5.4.1.1 of Exhibit A of the Application. The associated staff requests for additional information (i.e., 5.4.1-2, -3, -4, and –5) and the Duke Energy responses to them are provided later in this attachment.

RAI 3.4.4-1 (11/20/98A)
Section 3.4.3 of the license renewal application references report BAW-2243A. Section 3.4.4 references BAW-2244A. These reports do not address specific time limited aging analyses for the reactor coolant system piping or for the pressurizer. It is left up to the individual plant to address this issue. Therefore, for Oconee Units 1, 2, and 3, we request that you provide a demonstration that the ASME Code Section III cumulative usage factor for all Reactor Coolant System Piping and Pressurizer Class 1 components will be less than or equal to 1.0 for 60 years of plant operation.

Response to RAI 3.4.4-1
A demonstration that cumulative usage factors for the pressurizer are acceptable for the period of extended operation is contained in Section 5.4.1.1 of Exhibit A of the Application. The associated staff requests for additional information (i.e., 5.4.1-2, -3, -4, and –5) and the Duke Energy responses to them are provided later in this attachment.

Prior to providing responses to RAIs 3.4.5-1 through 3.4.5-8, Duke would like to provide some background information concerning the staff review of BAW-2251, "Demonstration of the Management of Aging Effects for the Reactor Vessel," as an aid to the reader.

The B&W Owners Group, of which Duke Energy is a member, submitted BAW-2251 to the NRC for review and approval in June 1996. At the time of the preparation of the Application to renew the operating license of Oconee Nuclear Station, the staff review of BAW-2251 was still in progress. By letter dated September 18, 1998, the NRC staff provided the Draft Safety Evaluation (DSE) for BAW-2251. The B&W Owners Group provided written responses to the six open items that were contained in the DSE. The responses represented the consensus position of the B&W Owners Group, including Duke Energy. By letter dated November 20, 1998, the staff provided RAIs 3.4.5-1 through 3.4.5-8, several of which request Duke Energy to provide responses to some of the open items in the DSE. In addition, by letter dated December 2, 1998, the staff provided RAI 4.18-4, which requests that Duke Energy respond to one of the open items in the DSE again. At the time of the preparation of these responses to the staff requests for additional information, staff review of BAW-2251 was not complete. Upon completion of the staff review of BAW-2251 and the issuance of the Safety Evaluation, Duke will update its responses to the BAW-2251 renewal applicant action items, as necessary.

In order to facilitate staff review of the Duke Energy responses to the DSE Renewal Applicant Action Items, the DSE Open Items, and the staff requests for additional information related to BAW-2251, Duke Energy has prepared RAI Response Tables 3.4.5-1 and 3.4.5-2. RAI Response Table 3.4.5-1 addresses the renewal applicant action items and RAI Response Table 3.4.5-2 addresses the renewal applicant open items listed in the DSE. The DSE items and the applicable Oconee RAIs are provided in the left-hand column. The Oconee-specific responses to each DSE item is provided in the right-hand column adjacent to the applicable DSE item. Each response to a request for additional information either provides the information requested or directs the reader to a specific location in the Oconee License Renewal Application where the requested information is contained.

RAI Response Table 3.4.5-1 Oconee-Specific Response to BAW-2251 Renewal Applicant Action Items	
Action Items from Draft Safety Evaluation for BAW-2251 Dated 9/18/98 and Related Oconee RAIs	**Oconee-Specific Response**
4.1 Renewal Applicant Action Items The following are license renewal applicant action items to be addressed in the plant-specific license renewal application when incorporating the B&WOG topical report in a renewal application:	
(1) The license renewal applicant is to verify that its plant is bounded by the topical report. Further, the renewal applicant is to commit to programs described as necessary in the topical report to manage the effects of aging during the period of extended operation on the functionality of the reactor vessel components. Applicants for license renewal will be responsible for verifying that any such commitments are subject to appropriate regulatory control. Any deviations from the aging management programs within this topical report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1). **RAI 3.4.5-2(a)** The license renewal applicant is to verify that its plant is bounded by the topical report. Further, the renewal applicant is to commit to programs described as necessary in the topical report to manage the effects of aging during the period of extended operation on the functionality of the reactor vessel components. Duke Energy, the applicant for license renewal will be responsible for verifying that any such commitments are subject to appropriate regulatory control. As such, identify any deviations from the aging management	Please see Exhibit A of the Application, Section 2.4.5, for a description of the Oconee reactor vessels and the process used by Duke to ensure that BAW-2251 bounds the Oconee reactor vessels. Please see Exhibit A of the Application, Section 3.4.5, for a discussion of applicable aging effects and a listing of the programs credited for managing the applicable aging effects. Detailed descriptions of the aging management programs for the reactor vessel are provided in Chapter 4.0 of the Application. Please see Exhibit A of the Application, Section 5.4.2, for a summary of the TLAA applicable to the reactor vessel. This Oconee-specific response is also intended to address RAI 3.4.5-2 (a).

RAI Response Table 3.4.5-1
Oconee-Specific Response to BAW-2251 Renewal Applicant Action Items

Action Items from Draft Safety Evaluation for BAW-2251 Dated 9/18/98 and Related Oconee RAIs	Oconee-Specific Response
programs described in Topical Report BAW-2251. Evaluate any deviations on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	
(2) A summary description of the programs and evaluation of TLAAs is to be provided in the license renewal FSAR supplement in accordance with 10 CFR 54.21(d).	Please see Exhibit B of the Application.
(3) Since the staff has not made any finding on whether the B&WOG topical report provides the complete list of reactor vessel components subject to an aging management review or whether the scoping methodology is adequate, individual plant applicants will need to provide a comprehensive list of structures and components subject to an aging management review and the methodology for developing this list as part of their license renewal applications. Any components determined by the applicant to be subject to an aging management review for license renewal but not within the scope of the topical report are required to be addressed in the license renewal application.	Please see Section 2.4.5 of Exhibit A of the Application for a description of the reactor vessel and a list of the items subject to aging management review. Section 2.4.5 discussed the extent to which BAW-2251 bounds the Oconee reactor vessels.
(4) The B&WOG has determined that the lower CRDM service support structure, including the weld that connects the lower CRDM service support skirt to the reactor vessel closure head, and the reactor vessel support skirt, including the weld that connects the reactor vessel support skirt to the transition forging, are subject to an aging management review for license renewal. However, the B&WOG has decided to exclude them from the scope of the topical report. Thus, a renewal applicant needs to address them in its license renewal application. **RAI 3.4.5-2 (b)** B&WOG has determined that the lower control rod	The reactor vessel skirt (including the attachment weld to the transition forging) and control rod drive service structure (including the attachment weld to the reactor vessel head) are described in Sections 2.4.11.3 and 2.4.11.4, respectively, of Exhibit A of the Application. The applicable aging effects for the reactor vessel skirt and CRDM service structure are discussed in Section 3.4.11.2 of Exhibit A of the Application. Aging management programs that manage the applicable aging effects are listed in Section 3.4.11.5 and are described in Sections 4.5 and 4.18 of Exhibit A of the Application.

RAI Response Table 3.4.5-1
Oconee-Specific Response to BAW-2251 Renewal Applicant Action Items

Action Items from Draft Safety Evaluation for BAW-2251 Dated 9/18/98 and Related Oconee RAIs	Oconee-Specific Response
drive mechanism (CRDM) service support structure, including the weld that connects the lower CRDM service support skirt to the reactor vessel closure head, and the reactor vessel support skirt, including the weld that connects the reactor vessel support skirt to the transition forging, are subject to an aging management review for license renewal. However, the B&WOG has decided to exclude them from the scope of the Topical Report BAW-2251. Identify which aging effects are applicable to these components and describe your aging management program for these components in the license renewal application.	This Oconee-specific response is also intended to address RAI 3.4.5-2 (b).
(5) The license renewal application for Oconee needs to address the fatigue evaluation of the reactor vessel studs on a plant-specific basis.	Please see Section 5.4.1.1 of Exhibit A of the Application. Also see the response to RAI 5.4.1-2.
(6) A license renewal applicant needs to provide the plant-specific procedures and instrumentation used to assess the number of operational transients in its renewal application for staff review. The staff review will also include the number of operating cycles applicable to the reactor vessel studs.	Please see Section 5.4.1.3 of Exhibit A of the Application. Also see the response to RAI 5.4.1-5.
(7) The B&WOG identifies flaw growth acceptance in accordance with the ASME Section XI ISI program as a TLAA, but indicates that flaw growth acceptance evaluation is plant-specific, is not within the scope of the report, and will be resolved on a plant-specific basis. Thus, a license renewal applicant needs to address it in the renewal application.	Please see Section 5.4.1.2 of Exhibit A of the Application.
(8) Alloy 600 components in the reactor vessel such as CRDM housings and other penetrations may be subject to crack initiation and growth. The B&WOG originally proposed to use the ASME Section XI program, supplemented by leak	Please see Section 4.3.1 of Exhibit A of the Application. Also see the response to RAI 4.3.1-1 through 4.3.1-6.

RAI Response Table 3.4.5-1
Oconee-Specific Response to BAW-2251 Renewal Applicant Action Items

Action Items from Draft Safety Evaluation for BAW-2251 Dated 9/18/98 and Related Oconee RAIs	Oconee-Specific Response
detection and surveillance of boric acid, to manage cracking of Alloy 600 components. In an April 1, 1997, response to the staff's request for additional information concerning Generic Letter 97-01, "Stress Corrosion Cracking of Control Rod Drive Mechanisms and Other Vessel Head Penetrations," the B&WOG stated: "Each participating plant will address additional requirements for RV head penetrations, including closure head penetrations less than 2 inch N.S. (i.e., thermocouple nozzles at TMI-1 and ONS-2)." Thus, a license renewal applicant referencing the topical report will need to submit its plant-specific program to manage cracking of Alloy 600 components in the reactor vessel in its renewal application for staff review.	
(9) During the review of the topical report, the staff had a question regarding the need to update the reactor vessel fracture toughness estimates with new data as it become available. In its August 11, 1997, RAI response, the B&WOG states: "Each license renewal applicant will define a process to ensure that the time-dependent parameters used in the TLAA evaluations reported in BAW-2251 are tracked such that the TLAA remains valid through the period of extended operation. The process will be defined on a plant-specific basis at the time of the licensee renewal application." Thus, a license renewal applicant needs to describe such a process in its application for staff review. If new information affects the conclusions of the topical report for the applicant's plant, the applicant needs to update its TLAA evaluations as appropriate and provide the updated evaluations in its renewal application for staff review.	Please see Section 1.4 of Exhibit A of the Application, which describes the process to update the Application during the staff review.
(10) In its August 11, 1997, RAI response, the B&WOG indicated that Oconee Unit 2 and TMI Unit 1 will provide updated predictions of RT_{PTS}	Please see Section 5.4.2.1 of Exhibit A of the Application.

RAI Response Table 3.4.5-1
Oconee-Specific Response to BAW-2251 Renewal Applicant Action Items

Action Items from Draft Safety Evaluation for BAW-2251 Dated 9/18/98 and Related Oconee RAIs	Oconee-Specific Response
for welds WF-25 and SA-1526, respectively, when the plant-specific application for license renewal is submitted. For plants with an RT_{PTS} value for 48 EFPY exceeding the corresponding PTS screening criterion, a license renewal applicant must address the requirements in 10 CFR 50.61(b)(3) by developing, and requesting staff approval for reasonably practicable flux reduction programs to avoid exceeding the PTS criterion.	

RAI Response Table 3.4.5-2 Oconee-Specific Response to BAW-2251 DSE Open Items	
Reactor Vessel Report, BAW-2251 Renewal Applicant Action Items DSE Open Items and Related Oconee RAIs	**Oconee-Specific Response**
4.2 Open Items The following are open items that need to be resolved prior to approval of BAW-2251.	
(1) **Intended Function of Reactor Vessel Components** In addition to the intended functions identified in BAW-2251, the staff believes that there is an another intended function-maintaining the capability to shut down the reactor and maintain it in a safe-shutdown condition. For example, certain reactor vessel components such as CRDM nozzles are needed to perform this additional intended function. **RAI 3.4.5-3** Identify whether the intended function of the reactor vessel internals is to maintain the capability to shut down the reactor and maintain it in a safe-shutdown condition.	Duke does not believe that the function suggested by the NRC—i.e., maintaining the capability to shut down the reactor and maintain it in a safe shutdown condition—is a reactor vessel component intended function. Rather, Duke believes that the function in question, which is a scoping function taken directly from §54.4 (a)(1)(ii), is a system level function. A number of components and items are required to shutdown the reactor and maintain it in a safe shut down condition: for example, CRDM nozzles, CRDM motor tubes, pressurizer, reactor coolant system piping, OTSGs, reactor coolant pumps, reactor vessel nozzles, RV shell, RV internals, decay heat drop line, decay heat pumps, and decay heat coolers. In accordance with prior B&WOG discussions with the NRC regarding the RCS piping report (i.e., DSE Open Item 1 regarding BAW-2243), the NRC stipulated that "the rule requires at §54.21(a)(3) that a renewal applicant demonstrate that the intended functions are maintained at the basic structure or component level rather than the system level." In addition, the intended function in question would not add any RV items as subject to aging management review. The evaluation of the integrity of pressure boundary requires a more rigorous demonstration of aging management than that of a system level function. This Oconee-specific response is also intended to address RAI 3.4.5-3.

RAI Response Table 3.4.5-2
Oconee-Specific Response to BAW-2251 DSE Open Items

Reactor Vessel Report, BAW-2251 Renewal Applicant Action Items DSE Open Items and Related Oconee RAIs	Oconee-Specific Response
(2) **Flow Stabilizers Subject to Aging Management Review** The staff has concerns about whether the flow stabilizers should be excluded from an aging management review for license renewal. Although the flow stabilizers themselves do not have safety-related functions, they were installed to address FIV problems experienced during hot functional testing. The staff's first concern is that the failure of the flow stabilizers could result in FIV and prevent satisfactory accomplishment of the intended functions of the reactor vessel components. Thus, the flow stabilizers may meet 10 CFR 54.4(a)(2) and be subject to an aging management review for license renewal. The staff's second question relates to potential cracking of the attachment weld of the flow stabilizer to the reactor vessel. Cracking of the attachment weld may cause the reactor vessel shell to crack thereby affecting its intended functions. Thus, the potential cracking of the attachment weld should be managed for license renewal.	The flow stabilizers (a.k.a., turning vanes) were not installed to address flow induced vibration concerns as suggested by the NRC. As stated in BAW-2251, Section 2.5.4, the original 10-inch high flow stabilizers were installed to promote mixing of the downcomer fluid in the lower head of the reactor vessel. However, after the incore monitoring system nozzles at Oconee Unit 1 failed during hot functional testing, the flow stabilizers were ground down from a height of 10-inches to 1-inch to reduce the hydraulic forces on the section of the incore monitoring system nozzles that extends from the lower head of the reactor vessel to the reactor vessel internals. In addition, the incore monitoring system nozzles were reinforced to prevent flow induced vibration concerns as described in Section 2.2.4 of BAW-2251 and as show in Figure 2-10 of BAW-2251. The flow stabilizers are made of stainless steel and are attached to the stainless steel cladding with stainless steel weld material.
RAI 3.4.5-4 The staff has concerns about whether the flow stabilizers should be excluded from an aging management review for license renewal. Although the flow stabilizers themselves do not have safety-related functions, they were installed to address flow-induced vibration (FIV) problems experienced during hot functional testing. Thus, cracking of the attachment weld may cause the reactor vessel shell to crack thereby affecting its intended functions. Indicate if an aging management program is provided to manage the aging effects on the flow stabilizers. If so, provide the details of such a program; if not justify why such a program is not needed to ensure the integrity of these stabilizers over the extended life	In accordance with the Statement of Considerations for 10 CFR Part 54, under the section entitled, "Systems, structures and components within the scope of license renewal," and within paragraph (iii) entitled "Bounding the scope of review," the following text appears. "An applicant for license renewal should rely on the plant's CLB, actual plant specific experience, industry-wide operating experience as appropriate, and existing engineering evaluations to determine those non-safety related systems, structures, and components that are the initial focus of the license renewal review. Consideration of hypothetical failures that could result from system interdependencies that are not part of the CLB and that have not been previously experienced is not

RAI Response Table 3.4.5-2 Oconee-Specific Response to BAW-2251 DSE Open Items	
Reactor Vessel Report, BAW-2251 Renewal Applicant Action Items DSE Open Items and Related Oconee RAIs	**Oconee-Specific Response**
for the units. **RAI 4.18-4** What is the aging management program for the flow stabilizers inside the reactor pressure vessel (Refer open item 4.2(2) in the topical report BAW-2251)?	required." Failure of the flow stabilizers has not occurred at any of the Oconee units, as verified by a review of plant-specific inservice inspection records. Duke considers the question regarding failure of the flow stabilizers a hypothetical failure and this system interdependency is not part of the current licensing basis. Therefore, the flow stabilizers are not subject to aging management review, as reported in BAW-2251. This Oconee-specific response is also intended to address RAIs 3.4.5-4 and 4.18-4
(3) **Wear of Core Guide Lugs** The staff considers loss of material due to mechanical wear of the core guide lugs a potential applicable aging effect that should be managed for license renewal. This potential aging effect is discussed in Section 3.1 of the working draft standard review plan for license renewal (Reference 6). **RAI 3.4.5-5** The staff considers loss of material due to mechanical wear of the core guide lugs a potential applicable aging effect that should be managed for license renewal. This potential aging effect is discussed in Section 3.1 of the working draft standard review plan for license renewal. Indicate if an aging management program is provided to manage the aging effects on the lugs. If so, provide the details of such a program; if not justify why such a program is not needed to ensure the integrity of the lugs over the extended life for the units.	The guide lugs are designed to arrest the fall of the core and internals during a postulated condition resulting form the severance of a circumferential weld joint at the core support ledge. During both cold conditions and normal operation the reactor vessel internals shock pads and the core guide lugs are separated by a gap and are not in contact with one another. Loss of material is not possible for the portion of the guide lugs below the shock pads owing to the clearance. Two guide blocks, which are bolted to the lower internals, surround the sides of each guide lug. The guide blocks do not transmit structural loads to the guide lugs during normal operation. The guide blocks are in close proximity to the guide lugs and slight indentations on the sides of selected guide lugs have been observed at one B&W operating plant (See BAW-2248, Section 3.5.3). Therefore, loss of material at the locations where the reactor vessel internals guide blocks surround the sides of the guide lugs is an applicable aging effect.

RAI Response Table 3.4.5-2
Oconee-Specific Response to BAW-2251 DSE Open Items

Reactor Vessel Report, BAW-2251 Renewal Applicant Action Items DSE Open Items and Related Oconee RAIs	**Oconee-Specific Response**
	ASME Section XI, Table IWB-2500-1, Examination Categories B-N-1 and B-N-2, which require visual examination of the inner surface of the RV and visual examination of the core guide lug attachment welds, respectively, will manage loss of material of the core guide lugs. This Oconee-specific response is also intended to address RAI 3.4.5-5.
(4) **Underclad Cracking** Cracking has been detected under the austenitic stainless steel weld cladding in reactor vessel forgings. When cracks are detected, the licensee performs a TLAA to evaluate the integrity of the reactor vessel. However, the staff considers the potential for underclad cracks to grow during plant operation an applicable aging effect to be managed for license renewal. Thus, the B&WOG should identify underclad cracking as a potential aging effect and propose an appropriate aging management program. One option may be to inspect forgings at the clad-forging interface in an area with the greatest amount of radiation. **RAI 3.4.5-6** Cracking has been detected under the austenitic stainless steel weld cladding in reactor vessel forgings. When cracks are detected, the licensee performs a time-limited aging analysis (TLAA) to evaluate the integrity of the reactor vessel. However, the staff considers the potential for underclad cracks to grow during plant operation an applicable aging effect to be managed for license renewal. Indicate if an aging management program is provided to manage the aging effects on the stainless steel cladding in the forgings. If so, provide the details of such a program. If not, justify why such a program is not needed to ensure	Intergranular separations were identified during the original manufacture of the SA 508, Class 2, low-alloy steel forgings. These were not service-induced flaws. Growth of these intergranular separations in SA 508, Class 2, low-alloy steel forgings is identified as an applicable aging effect in Section 3.1 of BAW-2251. The evaluation of the growth of these intergranular separations is described in Appendix C to BAW-2251. Treatment of intergranular separations through the TLAA evaluation is consistent with the current licensing basis of the B&W operating plants. For the initial 40-year life of the plants, an evaluation was provided in BAW-10013 that was evaluated by the Atomic Energy Commission (AEC). Inspections for growth of intergranular separations of the subject forgings were not required when the AEC issued the safety evaluation for BAW-10013. In addition, since the number of design transients (e.g., heatups and cooldowns) that contribute to the growth of the intergranular separations will not change for the period of extended operation, the growth originally expected over 40 years of operation is equivalent to the growth over 60 years of operation. Section 54.21 (c) requires each identified TLAA to be evaluated using any one of three alternatives.

RAI Response Table 3.4.5-2
Oconee-Specific Response to BAW-2251 DSE Open Items

Reactor Vessel Report, BAW-2251 Renewal Applicant Action Items DSE Open Items and Related Oconee RAIs	**Oconee-Specific Response**
the integrity of reactor vessel forgings.	Duke believes that growth of intergranular separations has been adequately evaluated for the period of extended operation through the TLAA reported in Appendix C of BAW-2251. In addition, the staff has found this evaluation acceptable as described in Section 3.4.4 and Appendix C of the staff's draft safety evaluation. Accordingly, Duke does not believe that any additional aging management programs are needed to manage this TLAA (i.e., growth of intergranular separations). This Oconee-specific response is also intended to address RAI 3.4.5-6.
(5) **Neutron Fluence** The extent of neutron embrittlement depends on the neutron fluence. As discussed in Section 1.2 above, the B&WOG is addressing its neutron fluence estimation methodology separately in Reference 3, which is under separate staff review. The staff has issued two sets of RAIs on Reference 3, and the B&WOG response is pending. The staff evaluation of the extent of neutron embrittlement discussed in this safety evaluation depends on the staff approval of Reference 3. Because the staff review of Reference 3 is not completed, neutron fluence is considered an open item until properly addressed by the B&WOG.	Please see the Oconee *Reactor Vessel Integrity Program, Fluence and Uncertainty Calculations,* in Section 4.24.3 of Exhibit A of the Application.

RAI Response Table 3.4.5-2
Oconee-Specific Response to BAW-2251 DSE Open Items

Reactor Vessel Report, BAW-2251 Renewal Applicant Action Items DSE Open Items and Related Oconee RAIs	**Oconee-Specific Response**
(6) **Reactor Vessel Materials Surveillance Program** The B&WOG should either have surveillance capsules irradiated in place during any period of plant operation or demonstrate that the surveillance data previously irradiated in a host reactor is applicable for the extended license term. The B&WOG should also describe the operating limitations necessary for ensuring that each plants' operating conditions (temperature and neutron [illegible]ce) do not invalidate the surveillance data [illegible]ed during the period of extended operation. **RAI 3.4.5-7** To ensure that the results of fracture toughness tests remain valid during the extended license period, describe the operating limitations necessary for ensuring that each plants' operating conditions (temperature and neutron fluence) do not invalidate the results of fracture toughness tests conducted on surveillance capsules removed from the Oconee reactor pressure vessels during the original 40-year license periods for the plants.	The Oconee units plan to rely on capsule data irradiated in "host" reactors for the period of extended operation, as discussed in the B&W Owners Group response to RAIs #10 and #15 regarding the reactor vessel report, BAW-2251. The data needed for the period of extended operation has either already been obtained and tested or will be obtained by the end of Cycle 17 at DB-1 and CR-3. It is estimated that Cycle 17 will occur in approximately 2008 to 2010 for CR-3 and DB-1, which is during the current term of operation for the Oconee units. In response to RAI #10 on BAW-2251, the B&WOG provided in-vessel capsule fluence values and associated withdrawal schedules for limiting beltline welds The target fluence values for the capsules were compared to the expected peak 48 EFPY fluence estimate at the inside surface of the RV. The comparison confirms that the necessary data for the period of extended operation has been obtained or will be obtained during the current term of operation. A comparison of reactor inlet temperatures is provided in Chapters 3.0 and 4.0 of BAW-1543, Revision 4. The inlet temperatures for the B&W plants are nearly identical (DB-1 inlet temperature is approximately 2 °F higher than the other B&W plants owing to a higher average temperature in the vessel). The inlet temperature for the B&W and Westinghouse reactors are within approximately 10 °F of each other during full power operation and approximately 25 °F when operating at 70% power. Regulatory Guide 1.99, Revision 2, Section B, states that a range of $\pm$ 25 °F is an acceptable range for application of the Regulatory Guide. In addition, capsules with identical materials that have been irradiated in B&W and

RAI Response Table 3.4.5-2
Oconee-Specific Response to BAW-2251 DSE Open Items

Reactor Vessel Report, BAW-2251 Renewal Applicant Action Items DSE Open Items and Related Oconee RAIs	**Oconee-Specific Response**
	Westinghouse units to characterize the effect of plant-to-plant differences in design and operating conditions are currently being tested. The results of these tests are currently scheduled to be published by 2000. As described in Chapter 4.0 of BAW-1543, Revision 4, the MIRVP meets the requirements of 10 CFR Part 50, Appendix H, Paragraph II.C, with regard to the requirements for an integrated program. Chapter 4.0 of BAW-1543, Revision 4, provides the technical basis for the integrated program with regard to the following design and operating parameters that are relevant to neutron radiation damage: fluence rate, neutron energy spectrum, irradiation temperature, and gamma heating. The NRC accepted the technical basis for the integrated program with regard to design and operating conditions through their approval of BAW-1543, Revision 4, including Supplements 1 and 2, in the NRC Safety Evaluation dated July 11, 1997 [Letter from D.B. Matthews of the NRC to J.H. Taylor of FTI dated July 11, 1997-Project 693]. Duke believes that the MIRVP data obtained during the current term of operation will be valid for the period of extended operation provided the technical basis for the integrated program, as discussed in Chapter 4.0 of BAW-1543, Revision 4, are not violated during the period of extended operation. In order to ensure that the MIRVP data remains valid for the period of extended operation, the following activities will be addressed by Duke through the Oconee *Reactor Vessel Integrity Program,* which is described in Section 4.24 of Exhibit A of the Application:

RAI Response Table 3.4.5-2 Oconee-Specific Response to BAW-2251 DSE Open Items	
Reactor Vessel Report, BAW-2251 Renewal Applicant Action Items DSE Open Items and Related Oconee RAIs	**Oconee-Specific Response**
	1. Fluence at the inside surface of the reactor vessel must be monitored physically or analytically during the period of extended operation to ensure that the capsule data obtained during the current term of operation remains valid during the period of extended operation. Descriptions of the Oconee cavity Dosimetry Program and the Oconee Fluence and Uncertainty Calculations are provided in Sections 4.24.2, *Cavity Dosimetry Program* and 4.24.3, Fluence *and Uncertainty Calculation,* respectively, of Exhibit A of the Application. The *Cavity Dosimetry Program* includes ex-vessel cavity dosimetry for Unit 2. 2. Modifications to design and operation that result in changes to the neutron energy spectrum relative to that discussed in Chapter 4 of BAW-1543, Revision 4, must be compared to the energy spectrum in which the capsules were irradiated. If appropriate, the surveillance data obtained during the current term of operation must be adjusted to account for the revised neutron energy spectrum. The subsequent impact on the applicable embrittlement evaluations must be assessed. A description of *Master Integrated Reactor Vessel Surveillance Program* is provided in Section 4.24.1 of Exhibit A of the Application. The requirement regarding modifications to design and operation that result in changes to neutron energy spectrum relative to that discussed in BAW-1543, Revision 4, will be added to Section 4.24.1 of Exhibit A of the Application within the attribute entitled "Acceptance Criteria or Standard."

RAI Response Table 3.4.5-2
Oconee-Specific Response to BAW-2251 DSE Open Items

Reactor Vessel Report, BAW-2251 Renewal Applicant Action Items DSE Open Items and Related Oconee RAIs	Oconee-Specific Response
	3. Modifications to design and operation that result in changes to gamma heating relative to that discussed in BAW-1543, Revision 4, must be evaluated since gamma heating affects the 1/4T location. Gamma heating is a function of neutron energy spectrum, which, at present, is similar for all of the reactors participating in the MIRVP. If the neutron spectrum changes and gamma heating changes, the surveillance data obtained during the current term of operation must be adjusted to account for the revised gamma heating. The subsequent impact on the applicable embrittlement evaluations must be assessed. A description of *Master Integrated Reactor Vessel Surveillance Program* is provided in Section 4.24.1 of Exhibit A of the Application. The requirement regarding modifications to design and operation that result in changes to gamma heating relative to that discussed in BAW-1543, Revision 4, will be added to Section 4.24.1 of Exhibit A of the Application within the attribute entitled "Acceptance Criteria or Standard." 4. Modifications to design and operation that result in reactor vessel inlet temperature changes relative to those discussed in Chapters 3 and 4 of BAW-1543, Revision 4, must be assessed relative to the inlet temperature at which the applicable capsules were irradiated. For example, changes in operating temperatures may occur during the period of extended operation due to power uprates. If appropriate, the surveillance data obtained during the current term of operation must be adjusted to account for the revised vessel inlet temperatures. The subsequent impact on the applicable embrittlement evaluations must be

RAI Response Table 3.4.5-2
Oconee-Specific Response to BAW-2251 DSE Open Items

Reactor Vessel Report, BAW-2251 Renewal Applicant Action Items DSE Open Items and Related Oconee RAIs	**Oconee-Specific Response**
	assessed. A description of *Master Integrated Reactor Vessel Surveillance Program* is provided in Section 4.24.1 of Exhibit A of the Application. The requirement regarding modifications to design and operation that result in changes to reactor vessel inlet temperature neutron energy spectrum relative to that discussed in BAW-1543, Revision 4, will be added to Section 4.24.1 of Exhibit A of the Application within the attribute entitled "Acceptance Criteria or Standard." 5. At present, Oconee-specific operating limitations are not needed to ensure that the parameters discussed above remain valid during the period of extended operation. The *Reactor Vessel Integrity Program* described in Section 4.24 of Exhibit A of the Application will provided assurance that the fracture toughness tests will remain valid during the period of extended operation. This Oconee-specific response is also intended to address RAI 3.4.5-7.

RAI 3.4.5-1 (11/20/98G)
The following general issue with respect to plant aging needs to be addressed:
Based on its evaluation of operating experience, the NRC has determined that potential aging effect mechanisms in components of pressurized water reactor vessels are as indicated in the Table 3.1-3 of the Draft Standard Review Plan for License Renewal. Table 3.1-3 identifies components that are considered part of the reactor pressure vessel (RPV) and identifies the associated aging effects for the components. Identify the equivalent components in the Oconee reactor pressure vessels and identify the aging effects (identified as significant or unresolved in Table 3.1-3) applicable to these components and where they are addressed in the application. For those aging effects that are not addressed explain why they are not applicable.

Response to RAI 3.4.5-1
Duke has reviewed Table 3.1-3 of the Working Draft Standard Review Plan for License Renewal (SRP-LR) and all of the items listed in the SRP-LR that apply to the B&W-designed Oconee reactor vessels are addressed in the B&W Owners Group Reactor Vessel Report--BAW-2251 [Reference 3.4-3 in the Oconee Application], the NRC's Draft Safety Evaluation regarding BAW-2251 [NRC letter from C.I. Grimes to D. J. Firth, dated September 18, 1998, entitled "Draft Safety Evaluation Concerning the B&WOG Generic License Renewal Topical report entitled, Demonstration of the Management of Aging Effects for the Reactor Vessel, BAW-2251, June 1996."], and the B&WOG responses to the NRC's Draft Safety Evaluation open items [FTI letter from David J. Firth to Jack W. Roe, OG-1725, October 30, 1998, B&WOG Generic License Renewal Program Topical Report BAW-2251, "Demonstration of the Management of Aging Effects for the Reactor Vessel," Responses to Open Items in Draft Safety Evaluation]. A comparison of the reactor vessel items and associated aging effects listed in Table 3.1-3 of the SRP-LR to the RV items and associated aging effects described in BAW-2251 is provided in RAI Response Table 3.4.5-3.

Table 3.4.5-3--Comparison of BAW-2251 to SRP-LR (Table 3.1-3)
Part of the response to RAI 3.4.5-3

Reactor Vessel Item	Equivalent Item in BAW-2251, DSE, or Oconee Application/Location	SRP Aging Effects U-Unresolved S-Significant	BAW-2251 Applicable Aging Effect(s)
Closure Head Dome	Closure Head Assembly/ BAW-2251, Section 2.1.2, Page 2-4	Crack Initiation & Growth (U) Loss of Material (S)	Cracking at Welded Joints Cracking of base metal-closure head ring 508 forgings Loss of External Material (boric acid)
CRD Mechanism Housing	Control Rod Drive Mechanism Nozzles/BAW-2251 Section 2.2.5, Page 2-6 See Sections 2.4.9 and 3.4.9 of Oconee Application for discussion of CRDM Motor Tube Housings	Crack Initiation & Growth (U) Loss of Material (S)	Cracking at or Near Welded Joints Loss of Material at CRDM Adapter Flange by wear CRDM Housings are Alloy 600 and are not susceptible to loss of material by boric acid wastage
Refueling Seal Ledge	Not within the scope of BAW-2251 and not subject to aging management review (see DSE, Section 3.1.2.5.1.6)	Crack Initiation & Growth (U)	Not Applicable
Closure Head Lifting Lugs	Not within the scope of BAW-2251 and not subject to aging management review (see DSE, Section 3.1.2.5.1.3)	Crack Initiation & Growth (U)	Not Applicable
Shroud Support Ring	Not applicable to B&W design	Crack Initiation & Growth (U)	Not Applicable
Closure Head Flange	Closure Head Assembly BAW-2251, Section 2.1.2, Page 2-3	Crack Initiation & Growth (U) Loss of Material–Boric Acid (S) Wall Thinning (S) Attrition/Wear (S)	Cracking at Welded Joints and Base Metal Loss of External Material-boric acid Loss of Material-wear and erosion
Closure Stud Assembly	Closure Stud Assemblies BAW-2251, Section 2.4.1, Page 2-7	Crack Initiation & Growth (S) Loss of Material (S)	Cracking Loss of Material-wear and boric acid Loss of Preload/Stress Relaxation

Table 3.4.5-3--Comparison of BAW-2251 to SRP-LR (Table 3.1-3)
Part of the response to RAI 3.4.5-3
(continued)

Reactor Vessel Item	Equivalent Item in BAW 2251, DSE, or Oconee Application/Location	SRP Aging Effects U-Unresolved S-Significant	BAW-2251 Applicable Aging Effect(s)
Vessel Flange	Upper Shell Assembly *(Upper Shell Flange)* BAW-2251, Section 2.1.1.1, Page 2-3	Crack Initiation & Growth (U) Loss of Material (S) Wall Thinning (S) Attrition/Wear (S)	Cracking at Welded Joints Loss of External Material-boric acid Loss of Material at internal support shelf Loss of Material-flange surface (wear and erosion)
Leakage Monitoring Tubes	Not within the scope of BAW-2251 and not subject to aging management review/DSE, Section 3.1.2.5.1.2	Crack Initiation & Growth (U)	Not Applicable
Upper (Nozzle) Shell	Upper Shell Assembly BAW-2251, Section 2.1.1.1, Page 2-3	Crack Initiation & Growth (U) Loss of Fracture Toughness (Neutron Embrittlement) (S)	Cracking at Welded Joints Cracking of Base Metal-508 forgings Loss of External Material-boric acid Reduction of Fracture Toughness-lower nozzle forging only (neutron embrittlement)
Primary Coolant Nozzles	Reactor Vessel Nozzles BAW-2251, Section 2.2, Page 2-5	Crack Initiation & Growth (U) Loss of Fracture Toughness (Neutron Embrittlement) (S)	Cracking at Welded Joints Loss of External Material-boric acid Reduction of Fracture Toughness not Significant for Inlet and Exit Nozzles per DSE, Section 3.3.4.1
Intermediate & Lower Shell	Shell Assembly (Intermediate & Lower Shell Area) BAW-2251, Section 2.1.1.2, Page 2-3	Crack Initiation & Growth (U) Loss of Fracture Toughness (Neutron Embrittlement) (S)	Cracking at Welded Joints and Repair Welds Cracking of Base Metal-508 forgings Loss of External Material-boric acid Reduction of Fracture Toughness (neutron embrittlement)

Table 3.4.5-3--Comparison of BAW-2251 to SRP-LR (Table 3.1-3)
Part of the response to RAI 3.4.5-3
(continued)

Reactor Vessel Item	Equivalent Item in BAW 2251, DSE, or Oconee Application/Location	SRP Aging Effects U-Unresolved S-Significant	BAW-2251 Applicable Aging Effect(s)
Core Support Pads (Lugs)	Reactor Vessel Interior Attachments BAW-2251, Section 2.3, Page 2-7 (*Guide Lugs* for B&W plants)	Crack Initiation & Growth (U) Attrition (Wear) (S)	Cracking at or Near Attachment Welds Loss of Material-wear (see B&WOG response to DSE Open Item 3)
Bottom Head Dome	Lower Vessel Head Assembly BAW-2251, Section 2.1.1.3, Page 2-6	Crack Initiation & Growth (U)	Cracking at Welded Joints Loss of External Material-boric acid
Instrumentation Tubes/Penetrations	Incore Instrumentation Nozzles BAW-2251, Section 2.2.4, Page 2-6	Crack Initiation & Growth (U)	Cracking at or Near Welded Joints

Set # 04
February 17, 1999

Note: Questions 3.4.5-2 through 3.4.5-8 discuss how the Oconee license renewal application relates to BAW-2251. There are aspects of the questions that involve Sections 3.4.5, 4.24, and 5.4.2 of Oconee's license renewal application. The questions have all been placed in this section for convenience.

RAI 3.4.5-2 (11/20/98G)
The following are action items to be addressed by a plant-specific license renewal application when incorporating by reference the Babcock & Wilcox Owners Group (B&WOG) topical report, BAW-2251. Provide the following:

(a) The license renewal applicant is to verify that its plant is bounded by the topical report. Further, the renewal applicant is to commit to programs described as necessary in the topical report to manage the effects of aging during the period of extended operation on the functionality of the reactor vessel components. Duke Energy, the applicant for license renewal will be responsible for verifying that any such commitments are subject to appropriate regulatory control. As such, identify any deviations from the aging management programs described in Topical Report BAW-2251. Evaluate any deviations on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).

(b) B&WOG has determined that the lower control rod drive mechanism (CRDM) service support structure, including the weld that connects the lower CRDM service support skirt to the reactor vessel closure head, and the reactor vessel support skirt, including the weld that connects the reactor vessel support skirt to the transition forging, are subject to an aging management review for license renewal. However, the B&WOG has decided to exclude them from the scope of the Topical Report BAW-2251. Identify which aging effects are applicable to these components and describe your aging management program for these components in the license renewal application.

Response to RAI 3.4.5-2
(a) Please see the Oconee specific response to Renewal Applicant Action Item (1) in RAI Response Table 3.4.5-1.

(b) Please see the Oconee specific response to Renewal Applicant Action Item (4) in RAI Response Table 3.4.5-1.

Set # 04
February 17, 1999

Note: Additional plant-specific open items that need to be addressed relative to the contents of the license renewal application and Topical Report BAW-2251 are discussed in question 3.4.5-3 through 3.4.5-8.

RAI 3.4.5-3 (11/20/98G)
Intended Function of Reactor Vessel Components
Identify whether the intended function of the reactor vessel internals is to maintain the capability to shut down the reactor and maintain it in a safe-shutdown condition.

Response to RAI 3.4.5-3
Please see the Oconee specific response to Open Item (1) in RAI Response Table 3.4.5-2.

RAI 3.4.5-4 (11/20/98G)
Flow Stabilizers Subject to Aging Management Review
The staff has concerns about whether the flow stabilizers should be excluded from an aging management review for license renewal. Although the flow stabilizers themselves do not have safety-related functions, they were installed to address flow-induced vibration (FIV) problems experienced during hot functional testing. Thus, cracking of the attachment weld may cause the reactor vessel shell to crack thereby affecting its intended functions. Indicate if an aging management program is provided to manage the aging effects on the flow stabilizers. If so, provide the details of such a program; if not justify why such a program is not needed to ensure the integrity of these stabilizers over the extended life for the units.

Response to RAI 3.4.5-4
Please see the Oconee specific response to Open Item (2) in RAI Response Table 3.4.5-2.

RAI 3.4.5-5 (11/20/98G)
Wear of Core Guide Lugs
The staff considers loss of material due to mechanical wear of the core guide lugs a potential applicable aging effect that should be managed for license renewal. This potential aging effect is discussed in Section 3.1 of the working draft standard review plan for license renewal. Indicate if an aging management program is provided to manage the aging effects on the lugs. If so, provide the details of such a program; if not justify why such a program is not needed to ensure the integrity of the lugs over the extended life for the units.

Response to RAI 3.4.5-5
Please see the Oconee specific response to Open Item (3) in RAI Response Table 3.4.5-2.

RAI 3.4.5-6 (11/20/98G)
Underclad Cracking
Cracking has been detected under the austenitic stainless steel weld cladding in reactor vessel forgings. When cracks are detected, the licensee performs a time-limited aging analysis (TLAA) to evaluate the integrity of the reactor vessel. However, the staff considers the potential for underclad cracks to grow during plant operation an applicable aging effect to be managed for license renewal. Indicate if an aging management program is provided to manage the aging effects on the stainless steel cladding in the forgings. If so, provide the details of such a program. If not, justify why such a program is not needed to ensure the integrity of reactor vessel forgings.

Response to RAI 3.4.5-6
Please see the Oconee specific response to Open Item (4) in RAI Response Table 3.4.5-2.

RAI 3.4.5-7 (11/20/98G)
Reactor Vessel Materials Surveillance Program
To ensure that the results of fracture toughness tests remain valid during the extended license period, describe the operating limitations necessary for ensuring that each plants' operating conditions (temperature and neutron fluence) do not invalidate the results of fracture toughness tests conducted on surveillance capsules removed from the Oconee reactor pressure vessels during the original 40-year license periods for the plants.

Response to RAI 3.4.5-7
Please see the Oconee specific response to Open Item (6) in RAI Response Table 3.4.5-2.

RAI 3.4.5-8 (11/20/98G)
Additional Limitations on Pressure-temperature (P-T) Limits and Reactor Coolant Pump Seal Limits
Based on the projected P-T limits at the end of the extended license period and other plant operating limits (e.g., limits of pump seal pressure), identify whether the operating windows for the Oconee units will be sufficient to start up and shut down the units at the end of the extended license period. If the operating windows are insufficient, provide aging management programs to increase the operating windows or reduce the amount of neutron embrittlement to the Oconee RPVs.

Response to RAI 3.4.5-8

Pressure-temperature (P-T) limit curves are addressed through the Oconee *Reactor Vessel Integrity Program* that is described in Section 4.24 of Exhibit A of the Application. Duke is in the process of updating the current P-T operating limits to 33 EFPY using the requirements of ASME Section XI, Appendix G, as modified by Code Case N-514 for the establishment of the reactor coolant inlet temperature at which low-temperature over pressurization (LTOP) systems shall be enabled, Code Case N-588 for circumferential flaws in welds, and Code Case N-626 for use of the K_{IC} fracture toughness curve. The results of the 33 EFPY analysis are complete and Oconee expects to submit the revised P-T operating limits to the NRC for approval at the end of March 1999.

The 33 EFPY P-T operating limits provide a significant increase in the existing operating window for all three Oconee units. For example, for Reactor Coolant System temperatures between 60 °F and 180 °F, the heatup allowable operating pressures increased by approximately 50%. For temperatures above 180 °F, the heatup allowable operating pressures increased by approximately 50% at 180 °F to 300% at 300 °F. Therefore, the use of Code Cases N-514, N-588, and N-626 resulted in a significant increase in the operating window at 33 EFPY when compared to the proposed 26 EFPY P-T operating limits for all Oconee units, which were submitted for staff review by letter dated October 15, 1998.

The P-T operating limits at the end of the period of extended operation were estimated by extending the 33 EFPY P-T calculations to 48 EFPY. Conservative estimates of 48 EFPY fluence were obtained for all three Oconee units using the methodologies outlined in BAW-2251, Appendix D, and BAW-2241P. Adjusted reference temperatures of the limiting beltline materials at 48 EFPY were calculated using a method consistent with that reported in the 26 EFPY P-T submittal. The 48 EFPY P-T operating limits were developed in accordance with the requirements of ASME Section XI, Appendix G, as modified by Code Cases N-514, N-588, and N-626. The 48 EFPY P-T operating limits were compared to the 33 EFPY P-T operating limits and the reduction in allowable operating pressure is approximately 5% between 60 °F and 180 °F. The reduction in allowable operating pressure at 48 EFPY varies from ≈5% at 180 °F to ≈15% at 300 °F. The predicted operating window at 48 EFPY is sufficient to conduct heatups and cooldowns and is significantly greater than the 26 EFPY P-T operating limits.

No additional aging management programs are necessary to ensure that the Oconee units maintain sufficient operating windows to conduct heatups and cooldowns during the period of extended operation. This conclusion is contingent on the NRC review and acceptance of the 33 EFPY P-T operating limits that are currently scheduled to be submitted to the NRC for review and approval in March 1999.

RAI 3.4.6-1 (11/20/98C)
Section 3.4.6.1 states that "Oconee Reactor Coolant System chemistry is maintained in accordance with the Oconee Chemistry Control Program." Provide a description of the extent and frequency of excursions from the primary coolant chemistry parameters for each plant. What is the impact of these excursions on the RVI components? Explain the basis for this conclusion.

Response to RAI 3.4.6-1
The Oconee *Chemistry Control Program* is discussed in Section 4.6 of Exhibit A of the Application. The Oconee units have not experienced any Level 3 excursions as defined by the EPRI Water Chemistry Guidelines (See response to RAI 4.6-3). In addition, a review of Oconee plant data from 1985 to present, as documented in the B&WOG response to GL 97-01 [B&WOG Integrated Response to Generic Letter 97-01: "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," BAW-2301, July 1997.], indicate that the Reactor Coolant System control parameters for chlorides and fluorides were slightly exceeded in only a few instances, and corrective actions were taken immediately. Sulfate excursions only occurred during shutdown and were reduced well below the control parameter prior to startup. Oxygen levels have never exceeded the administrative limits. The data for Oconee prior to 1985 are not easily retrievable; however, the units did measure conductivity on a set frequency and any large excursion would have been investigated and cleaned up immediately.

Therefore, the Oconee units have not experienced chemistry excursions that required engineering evaluation or the preparation of justification for continued operation. Based on operating experience and engineering judgment, Duke Energy has determined that the minor chemistry excursions experienced to date have a negligible impact on aging of the reactor vessel internals.

RAI 3.4.6-2 (11/20/98C)
Section 3.3 of BAW-2248 indicates that crevice corrosion is not expected to be a concern, unless the internals are exposed to a series of long outages, which have stagnation and high impurity levels. Has Oconee exceeded the impurity levels and cumulative outage time required to cause concern for crevice corrosion? What components are potentially affected?

Response to RAI 3.4.6-2:
Crevice corrosion is considered a severe form of pitting. As with pitting, crevice corrosion will not occur unless dissolved oxygen levels are above 100 ppb and halogens are above 150 ppb. In the presence of an oxygenated environment that contains impurites, the rate at

which loss of material by pitting and crevice corrosion occurs is dependent on temperature; the higher the temperature the higher the rate of corrosion. During shutdown, aerated primary coolant can have dissolved oxygen contents of approximately 8 ppm when the reactor vessel head is removed for refueling; however, temperatures are low and impurites are controlled during refueling (per the *Chemistry Control Program*) at levels that will preclude crevice or pitting corrosion.

During extended outages the plant may remain in cold shutdown with the Reactor Coolant System in the filled and pressurized condition with halogen and dissolved oxygen controlled to less than 150 ppb and 100 ppb, respectively. Degradation of reactor vessel internals by crevice or pitting corrosion following and extended outage has not been observed at Oconee. Therefore, crevice corrosion is not a significant degradation mechanism during extended outages owing to the Oconee *Chemistry Control Program,* which is described in Section 4.6 of Exhibit A of the Application.

RAI 3.4.7-1 (11/18/98B)
It is stated in Section 3.4.7.1 of the license renewal application that the once through steam generator (SG) is designed to accommodate all service loadings (i.e., Levels A through D); however, operation under Levels A and B service conditions contribute to the normal aging stresses for the once through SG items. The Oconee units have not been subjected to Levels C or D events. It is the staff's understanding that the tubes in Oconee Unit 3 were subjected to stresses slightly beyond the allowable values during an event in August 1994 involving the injection of cold feedwater into a hot, dry SG. Discuss whether or not this event contributed to the aging of the SG tubes. Describe the procedures that are used to evaluate the impact of such events on the adequacy of aging management programs.

Response to RAI 3.4.7-1
The Unit 3 event that occurred on August 10,1994, was a reactor trip from full power that resulted in the dry-out of the B once through steam generator (OTSG). The overcooling that occurred as a result of the inadvertent opening of a turbine bypass valve resulted in tube-to-shell differentials in excess of established tube-to-shell limits. Reactor trip is an upset event (i.e., Level B) and is not an emergency or faulted event (Level C or D). A subsequent evaluation by B&W using actual transient data indicated that the axial tube loads (both compressive and tensile) were within the limits of the allowable tube loads. Since the allowable tube loads were not exceeded, the event of August 10,1994, did not impact the integrity of the B OTSG tubes.

The procedure used to evaluate the impact of such events on age-related degradation of the Reactor Coolant System components is as follows. A review of Oconee operating history was conducted to confirm that the Oconee units have not been subjected to Level C or D events, and to determine if the severity of Level A and B exceeded the transient definitions in the design specification. No Oconee unit has experienced a Level C or D event, and, in general, the Oconee Reactor Coolant System components have operated within the design parameters defined by the Reactor Coolant System design specification for Level A and B events. The Oconee *Thermal Fatigue Management Program* ensures that the Reactor Coolant System design specification transients are tracked, including the severity of the transients. If a transient is registered that exceeds the transient definition defined by the design specification (e.g., cooldown limits exceeded or tube-to-shell differential limits exceeded), engineering evaluations are conducted to assess the impact of the event. The review of Oconee operating history revealed only a few instances where the transient conditions that occurred during a Level A or B event exceeded those defined by the design specification. In each instance an evaluation was performed using actual transient data and it was determined that the transient loads were well below the allowable loads. These events were determined to have a minimal impact on the aging of the applicable Reactor Coolant

System components and modifications to aging management programs owing to the occurrence of the events are not necessary.

RAI 3.4.7-2 (11/19/98B)

It is stated in Section 3.4.7.2.3 of the license renewal application that mechanical distortion is an applicable aging effect for the once through SG. The installation of sleeves in the SG tubes cause a distortion of the tube at the expansion joint of the sleeve. The increased stress in the tube makes it susceptible to circumferential cracking at this location. Discuss whether current measures to manage this aging effect during plant operation are considered adequate and sufficient to manage anticipated further aging during the extended period of operation of the SGs. If additional measures are planned to deal with this aging mechanism during the license renewal period, we request that you identify and discuss such measures in detail.

Response to RAI 3.4.7-2

Present eddy current inspection methods are sufficient to detect circumferential cracking of the tubes in the regions adjacent to the expansion joint between the sleeve and the tube. The inspection method employs a bobbin coil throughout the entire tube length to identify crack like indications. For regions of geometric discontinuities, such as the roll expansion in the tube sheet region and the roll expansions in the sleeve, a more accurate eddy current inspection is employed (e.g., rotating pancake coil probe). Flaws that exceed the acceptance criteria contained in the Technical Specifications are identified as defects. The affected tube may then be plugged or alternate repair criteria may be employed, which includes different acceptance criteria than that found in the Technical Specifications. The current inspection methods and subsequent evaluation procedures are sufficient for both the current term of operation and the period of extended operation with respect to inspection of the regions adjacent to the expansion joint between the sleeve and the tube.

Steam generator tube inspections are performed at Oconee in accordance with the *Steam Generator Tube Surveillance Program*, which is described in Section 4.26 of Exhibit A of the Application. Duke Energy will continue to evaluate and implement new inspection techniques through compliance with the EPRI standards referenced in NEI 97-06, "Steam Generator Program Guidelines," which include using qualified inspection techniques for specific types of tube degradation. The *Steam Generator Tube Surveillance Program* complies with the steam generator program guidelines established in NEI 97-06.

RAI 3.4.7-3 (11/19/98B)
It is stated in Section 3.4.7.2.1 of the license renewal application that fretting and sliding wear of SG tubes at the tube support locations has occurred in the industry. The forces imposed on the tubes by the secondary fluid cause high frequency vibration of the tubes and interaction with the tube support structures. The degradation of the supports due to loss of material can result in excessive vibration and eventual failure of the tubes due to fatigue or fluid elastic instability. Discuss whether current measures to manage this aging effect during plant operation are considered adequate and sufficient to manage potential further aging during the extended period of operation of the SGs. If additional measures are planned to deal with this aging mechanism during the license renewal period, we request that you identify and discuss such measures in detail.

Response to RAI 3.4.7-3
The internal baffle plates and tube support plates are not within the scope of license renewal and are not subject to aging management review since they do not support an OTSG intended function. (See response to RAI 3.4.7-4 for additional discussion concerning the internal baffle bolt plates and tube support plates.) Failure of the baffles and/or tube support plates may result in loss of an intended function; however, these items have not failed in service at any B&W plant and would thus be considered a hypothetical failure. Consideration of hypothetical failures is not required for scoping purposes in accordance with the Statement of Considerations, under the section entitled "Systems, structures and components within the scope of license renewal", and within paragraph (iii) entitled "Bounding the scope of review." The current inspection methods and subsequent evaluation procedures are sufficient for both the current term of operation and the period of extended operation with respect to inspection of the steam generator tubes in the vicinity of the tube support plates.

RAI 3.4.7-4 (12/3/98A)
Discuss why tube support plates and upper and lower cylindrical baffles are not within the scope of license renewal.

Response to RAI 3.4.7-4
Inside the generator shell there are steel cylindrical baffles and tube support plates that channel the feedwater flow down through the lower annulus, around the tubes, up between the tubes as it is boiled to steam, and then back down the upper annulus to the steam nozzles. These non-structural parts are supported by the secondary shell but do not support the secondary pressure boundary. The internal baffles and tube support plates do not support an intended function of the once through steam generator and are not subject to aging management review.

RAI 3.4.7-5 (12/3/98A)
Discuss why outside-diameter stress corrosion cracking is not considered an applicable aging effect for the OTSG tubes at Oconee. Discuss how this aging effect is managed, if different from those mechanisms already discussed for this component.

Response to RAI 3.4.7-5
The applicable aging effect for the OTSG tubes is cracking as discussed in Section 3.4.7.2.2 of Exhibit A of the Application. The license renewal rule does not require that specific aging mechanisms be discussed and cracking of the tubes may be attributed to primary water stress corrosion cracking, intergranular stress corrosion cracking, or outside diameter stress corrosion cracking. Outside diameter stress corrosion cracking has been observed in selected PWR steam generators in the United States and abroad. This mechanism has primarily been observed in recirculating steam generators at or near the tube support plates, at the top of the tubesheet, and in the U-bend region, but has not been identified as an active mechanism in OTSG tubes. Outer diameter stress corrosion cracking is not expected in the OTSGs because of the differences in the design of the OTSGs versus the recirculating steam generators. However, outside diameter stress corrosion cracking is a potential aging mechanism that may result in cracking of OTSG tubes.

At present, the eddy current tube inspection methods employed to detect cracking by primary water stress corrosion cracking, intergranular stress corrosion cracking, and loss of material by intergranular attack are sufficient to detect outside diameter stress corrosion cracking. No supplemental inspection techniques are required to detect outside diameter stress corrosion cracking for the period of extended operation. Duke will continue to evaluate and implement new inspection techniques through compliance with the EPRI standards referenced in NEI 97-06, "Steam Generator Program Guidelines" which include using qualified inspection techniques for specific types of tube degradation.

RAI 3.4.8-1 (11/18/98B)
It is stated in Section 3.4.8.3, page 3.4.22 of the license renewal application that the results of the review of NRC generic communications for the Reactor Coolant System piping report (BAW-2243A, Demonstration of the Management of Aging Effects for the Reactor Coolant Piping) are also applicable to the reactor coolant pump (RCP). Identify the parts of the RCP for which fatigue is considered plausible. Describe the review process used to evaluate these parts for fatigue.

Response to RAI 3.4.8-1
The reactor coolant pump items that are susceptible to fatigue are those items for which cumulative usage factors were calculated in the original design. A fatigue analysis was performed for the main flange bolts for the Westinghouse pumps at Oconee Unit 1; the casing, cover, and flange met the exemption from fatigue requirements and were not analyzed for fatigue. A fatigue analysis was performed for the casing, studs, wear ring, and cover/stuffing box for the Sulzer-Bingham pumps at Oconee Units 2 and 3. Demonstration of the acceptability of cumulative usage factors for all reactor coolant pump items for the period of extended operation is addressed in Section 5.4.1.1 of Exhibit A of the Application.

RAI 3.4.8-2 (11/18/98B)
Identify any subcomponents of the RCP for which fatigue usage is monitored. Also, describe how the monitored parameters are compared to the fatigue analysis of record.

Response to RAI 3.4.8-2
The reactor coolant pump items that were subjected to fatigue evaluations are listed in the Response to RAI 3.4.8-1. Fatigue of these items is addressed by the *Thermal Fatigue Monitoring Program* described in Section 5.4.1.3 of Exhibit A of the Application.

RAI 3.4.8-3 (11/18/98B)
Identify any modifications in the RCP or other components that may have had an impact on the fatigue usage of the subcomponents of the RCP. Also, describe the impact of the modification, if any, on the computation of previous fatigue usage and projection of fatigue usage to 60 years.

Response to RAI 3.4.8-3
No modifications were identified that affected the fatigue usage of the reactor coolant pump items.

Note: The following two questions (3.4.8-4, 3.4.8-5) apply to both sections 3.4.8 and 3.4.9.

RAI 3.4.8-4 (12/3/98A)
Discuss why the aging management program for Reactor Coolant System (RCS) Operational Leakage Monitoring described in section 4.23 would include within its scope the reactor coolant pump components but that this program is not credited in section 3.4.8.

Response to RAI 3.4.8-4

The *Reactor Coolant System Operational Leakage Monitoring Program* was inadvertently omitted from the discussion in Section 3.4.8 of Exhibit A of the Application.

RAI 3.4.8-5 (12/3/98A)

Discuss why the Chemistry Control Program cited in section 4.23 to be used in conjunction with RCS operational leakage monitoring is not credited for managing aging effects for the Reactor Coolant Pumps (3.4.8) or for the Control Rod Drive Tube Motor Housings (section 3.4.9).

Response to RAI 3.4.8-5

The *Chemistry Control Program* and *Reactor Coolant System Operational Leakage Monitoring Program* were inadvertently omitted from the discussion in Section 3.4.8 of Exhibit A of the Application. The *Chemistry Control Program* was inadvertently omitted from the discussion in Section 3.4.9 of Exhibit A of the Application.

RAI 3.5.5-1 (11/20/98A)
Show that the ASME Code Section III cumulative usage factor for all High Pressure Injection (HPI) System Class 1 piping and components in Oconee Units 1, 2, and 3, will be less than or equal to 1.0 for 60 years of plant operation, considering the thermal cycling effects of the following events:

a. Unanticipated outleakage in HPI/EI (emergency injection) lines, described in NRC Bulletin 88-08.
b. "Warming" make-up flow in HPI/NMU (normal makeup) lines, described in NRC Information Notice 97-46.

Response to RAI 3.5.5-1
A demonstration that cumulative usage factors for all High Pressure Injection System Class 1 piping are acceptable for the period of extended operation is contained in Section 5.4.1.1 of Exhibit A of the Application. The associated requests for additional information (i.e., 5.4.1-2, -3, -4, and –5) and Duke responses to them are provided later in this attachment. Inspections of High Pressure Injection System connections to the Reactor Coolant System due to IE Bulletin 88-08 are described in Section 4.22 of Exhibit A of the Application.

RAI 4.3.1-1 (11/20/98G)
In regard the content of Section 4.3.1, "Alloy 600 Aging Management Program" (henceforth the Alloy 600 AMP) to the License Renewal Application:

a. The section states that the Alloy 600 AMP will be used to identify and inspect the four most susceptible locations within the Oconee reactor coolant systems (RCS). Clarify whether the scope of the proposed inspections of the four most susceptible locations will be on different components within the RCS or on redundant ("sister") components in the RCS.

b. Clarify whether the aging management program (Section 4.10 of the License Renewal Application) for the Oconee Alloy 600 vessel head penetration (VHP) nozzles and associated Alloy 82/182 partial penetration welds is a separate program from the Alloy 600 AMP and if it will be implemented in addition to the Alloy 600 AMP.

Response to RAI 4.3.1-1
a. The Alloy 600 items and Alloy 82/182 weld metal susceptibility study has been completed. All of the Alloy 600 items and Alloy 82/182 welds within the Reactor Coolant System at each Oconee Unit were included in the study. The current methodology used to rank the Alloy 600 items and Alloy 82/182 welds is described in the Duke response to RAI 4.3.1-5. The top five location groupings with respect to susceptibility to PWSCC are listed below:

   1. CRDM Nozzle at Oconee Unit 2
   2. Pressurizer Heater Sleeves at Oconee Unit 1
   3. Pressurizer Level Taps and Safe Ends at Oconee Unit 3
   4. Pressurizer Spray Nozzle Safe Ends at Oconee Unit 3
   5. Pressurizer Vent Nozzle at Oconee Unit 3

   The aging management program for the CRDM penetrations is the *Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program,* which is described in Section 4.10 of Exhibit A of the Application. Aging management of the pressurizer heater sleeves is addressed by the *Pressurizer Heater Bundle Penetration Welds Examination*, which is described in Section 4.3.7.2 of Exhibit A of the Application. The weld that connects the pressurizer spray nozzle to the Alloy 600 safe end receives a volumetric examination each inspection interval at each Oconee unit in accordance with ASME Section XI. Current plans are to develop new inspection programs for the pressurizer level taps and safe ends and the vent nozzle.

b. The *Alloy 600 Aging Management Program* is a new Oconee program that is required for license renewal to manage cracking by PWSCC of Alloy 600 items and Alloy 82/182 welds. The *Alloy 600 Aging Management Program*, which is described in Section 4.3.1 of Exhibit A of the Application, is a requirement for license renewal as documented in the NRC final safety evaluations for B&WOG reports on Reactor Coolant System Piping, BAW-2243A, and the Pressurizer, BAW-2244A.

   The *Control Rod Drive Mechanism and Other Vessel Head Penetration Inspection Program* is an existing Oconee program, which is based on a B&WOG program. The program addresses the requirements of Generic Letter 97-01 and is described in Section 4.10 of Exhibit A of the Application.

   Currently, these two programs are considered to be separate programs at Oconee.

RAI 4.3.1-2 (12/3/98A)
Provide Oconee-specific operating experience related to primary-water stress corrosion cracking of Alloy 600 pressure boundary components or its associated weld metal <u>not related to</u> steam generator tubes, plugs or sleeves. Include a description of specific instances of cracking, the safety significance, and corrective action taken.

Response to RAI 4.3.1-2
Crack-like indications were detected on several Alloy 600 CRDM nozzles at Oconee Unit 2. The nozzles were re-inspected 2 years later with no growth of the crack-like indication reported (see Section 4.10 of Exhibit A of the Application). The Oconee units have not experienced any other instances of cracking of Alloy 600 or Alloy 82/182 by PWSCC, other than cracking of OTSG tubes, plugs, or sleeves.

RAI 4.3.1-3 (12/3/98A)
Are there RCS components fabricated from other Inconel alloys (e.g., Alloy 690 or Alloy 800)? What is the basis for concluding that SCC of these components is not applicable?

Response to RAI 4.3.1-3
No original Oconee Reactor Coolant System components were fabricated using Alloy 690 or Alloy 800 material. A recent repair was completed at Oconee Unit 3 that used Alloy 690 with Alloy 52 weld material in the installation of a hot leg thermocouple well. Current plans are to incorporate the recently completed Alloy 690 installation into the new *Alloy 600 Aging Management Program.*

However, within the Oconee *Alloy 600 Aging Management Program*, cracking by PWSCC of Alloy 690 is not an applicable aging effect since primary water stress corrosion cracking of Alloy 690 has not been observed. Alloy 690 plugs have been used in the Oconee steam generator tubes. These plugs have the same applicable aging effects and aging management programs as the other steam generator tube plugs previously identified.

RAI 4.3.1-4 (12/3/98A)
The Alloy 600 Aging Management Program will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1). Discuss how this schedule will provide sufficient information in a timely enough manner such that the possible need for corrective actions before the start of the renewed operating period. Provide a demonstration that implementation of this program will provide adequate assurance that the effects of aging will be detected and managed before there is a loss of the component intended function.

Response to RAI 4.3.1-4
The Oconee *Alloy 600 Aging Management Program* will not be "completed" by February 6, 2013. The initial inspection of the selected locations will be completed for this new program and the frequency of subsequent inspections will depend on the results of the initial inspections. The *Alloy 600 Aging Management Program* will continue through the end of the period of extended operation. Inspection frequency, acceptance criteria, and corrective actions are discussed in Section 4.3.1 of Exhibit A of the Application. Flaws that exceed the acceptance criteria must be evaluated or repaired prior to restart, as required by 10 CFR 50.55 (a) and ASME Section XI.

As specified in both the B&W Owners Group Reactor Coolant System Piping Report, BAW-2243A, and the Pressurizer Report, BAW-2244A, the Alloy 600 items (with the exception of the CRDM nozzles) and Alloy 82/182 welds in the B&W operating plants are believed to have a low susceptibility to primary water stress corrosion cracking owing to the heat treatment (i.e., stress relief) that the Reactor Coolant System components received during fabrication. Two comprehensive inspections of all sixty-nine Alloy 600 CRDM penetrations have been completed at Oconee Unit 2 with no defects observed; and, volumetric examinations of selected Alloy 600 and Alloy 82/182 locations in the pressurizer have been conducted in accordance with ASME Section XI, with no defects observed over two inspection intervals. Only one instance of through-wall cracking of an Alloy 600 item has been observed at a B&W operating plant [see BAW-2244A, B&W owners Group Pressurizer Report, ANO-1 level tap].

Cracking of Alloy 600 and Alloy 82/182 by primary water stress corrosion cracking is dependent on the simultaneous presence of tensile stress, high temperature, and a susceptible microstructure. The model used to predict susceptibility to primary water stress corrosion cracking, which is described in the Duke response to RAI 4.3.1-5, provides a reasonable means of ranking items with respect to susceptibility to PWSCC but the model is not accurate in predicting the time at which PWSCC will occur. Therefore, delaying the additional inspections to no later than February 6, 2013, is appropriate based on the following considerations: operating experience (both Oconee and other B&W operating plants) supports the postulate that component stress relief during fabrication may have been beneficial in the reduction of residual stresses that can lead to primary water stress corrosion cracking; assessment and inspection of the Alloy 600 CRDM nozzles will continue in accordance with GL 97-01; the ASME Section XI volumetric inspections of Alloy 600 and Alloy 82/182 items in the pressurizer (i.e., surge nozzle-to-safe end weld and spray nozzle-to-safe end weld); and, engineering judgment.

The program attributes defined in Section 4.3.1 of Exhibit A of the Application are consistent with ASME Section XI and provide reasonable assurance that the program will effectively manage primary water stress corrosion cracking of Alloy 600 items and Alloy 82/182 weld metal during the period of extended operation.

RAI 4.3.1-5 (12/3/98A)
Provide the elements/characteristics that are considered in the susceptibility study of alloy 600 components and alloy 82/182 weld locations in the reactor coolant system. When will this study be completed and how will it be validated?

Response to RAI 4.3.1-5
The elements/characteristics of the methodology that was used to perform a susceptibility ranking of Oconee Alloy 600 items and Alloy 82/182 welds includes the following steps:

1. Identify all Alloy 600 material and Alloy 82/182 weld material in use at Oconee

   These materials have been identified.

2. Select a primary water stress corrosion cracking (PWSCC) susceptibility model

   The model that was used to rank the susceptibility of Alloy 600 items and Alloy 82/182 welds to PWSCC is similar to the CRDM Nozzle PWSCC Inspection and Repair Strategic Evaluation (CIRSE) [see Section 2.3.3 and Appendix B of BAW-2301, July 1997, B&WOG Integrated Response to Generic Letter 97-01: Degradation of

Control Rod Drive mechanism and Other Vessel Closure head Penetrations] model that was applied to the CRDM penetrations. Use of a concordant method ensures consistency between the *Alloy 600 Aging Management Program* and the *CRDM and Other Vessel Head Penetration Inspection Program*, which are two separate but related programs at Oconee.

3. Select a reference Alloy 600 item for calculation of relative time to crack initiation.

   The reference item chosen for calculation of relative time to crack initiation is the ANO-1 pressurizer instrumentation nozzle that was identified as leaking in December 1990.

4. Evaluate the differences in material and operating parameters between the reference Alloy 600 part and the Oconee Alloy 600 items and Alloy 82/182 welds.

   The specific material and operational parameters that were compared include maximum operating inside surface stress, operating temperature, microstructure, surface condition, and water chemistry.

5. Calculate the relative susceptibility factor for the Oconee Alloy 600 items and Alloy 82/182 welds relative to the time of crack initiation for the reference Alloy 600 part.

   The differences in material and operational parameters were used to calculate a relative susceptibility factor, which is defined in Appendix B to BAW-2301, for each Oconee Alloy 600 item and Alloy 82/182 weld. The relative susceptibility factors were used to calculate an <u>estimated</u> time to crack initiation for a specific Oconee Alloy 600 part or Alloy 82/182 weld relative to the time of crack initiation for the reference part. The Oconee PWSCC susceptibility study was completed as a B&W Owners Group project and is part of site documentation at Oconee.

Validation of Model
At present, the B&W operating plants have experienced only two instances (other than OTSG tubes) of cracking by PWSCC: the ANO-1 pressurizer nozzle and the CRDM nozzle at Oconee Unit 2. The model described above was used to benchmark the events at the two B&W operating plants, and the predicted time to crack initiation was within a factor of 2. While the uncertainty in the prediction of time to crack initiation may be as large as a factor of 2 for the B&W operating plants, ranking of items using the relative susceptibility factors provides a quantitative means of selecting candidate items for inspection for license renewal.

RAI 4.3.1-6 (12/3/98A)
How are the aging effects on the Inconel components of the Core Flood System (section 3.5.5.1) managed? The Aging Management Program for Alloy 600 is not credited.

Response to RAI 4.3.1-6
The Alloy 600 items attached to the core flood tank are not susceptible to PWSCC owing to the low operating temperature of the core flood tank. In accordance with Section 3.5.5.1 of Exhibit A of the Application, cracking by SCC and loss of material of the Inconel Core Food System items are applicable aging effects that are controlled by *the Chemistry Control Program.*

RAI 4.3.7-1 (11/20/98D)
Section 4.3.7 of the license renewal application (LRA) indicates the pressurizer cladding, internal spray line, and spray head examinations will be performed once using visual examination (VT-3). Identify the resolution capability of the VT-3 visual examination techniques that will be used, and the crack size that the examination will be able to detect. Will the proposed examination be able to detect flaws before they reach a critical size? Justify why a one-time examination will ensure that the minimum detectable flaw does not grow to a size that will result in a fracture of the pressurizer. Are VT-1, augmented resolution capability, or any other examination methods necessary for detection of cracks resulting from operation during the license renewal term? Provide any analyses that have been performed which support your conclusions.

Response to RAI 4.3.7-1
Prior to providing a response to RAI 4.3.7-1, Duke would like to provide some background information concerning the staff review of BAW-2244A, "Demonstration of the Management of Aging Effects for the Pressurizer," and to clarify the purpose of the pressurizer cladding inspection, as an aid to the reader.

The B&W Owners Group, of which Duke Energy is a member, submitted BAW-2244 to the NRC for review and approval in August 1995. By letter dated November 26, 1997, the NRC staff provided the Final Safety Evaluation (FSE) for BAW-2244. The FSE contained two open items: (1) cracking of stainless steel cladding inside the pressurizer vessel, and (2) aging management of pressurizer heater penetration welds.

With regard to pressurizer cladding, Duke agrees with the B&WOG response to FSE Open Item 1 regarding BAW-2244 and maintains the position that cracking of stainless steel cladding, including attachment welds to cladding, is not an applicable aging effect for the period of extended operation. The industry operating experience (Haddam Neck) cited by the NRC is not applicable to the B&W-designed plants owing to differences in design, fabrication, and operation. Duke maintains that the cracking experienced at Haddam Neck was not attributed to the normal aging of the pressurizer. The cracking was either attributed to the spray of cold water from the spray nozzle during a low water level transient in the 1970 time frame, or present during initial startup. Since the initial detection of the Haddam Neck pressurizer clad cracking, the existing indications have been reexamined and found not to propagate due to normal conditions of operation. In addition, in response to NRC concerns, Southern California Edison Company performed a remote visual inspection of the internal clad surface of their San Onofre Unit 1 pressurizer (same design as the Haddam Neck pressurizer). No evidence of clad cracking was noted.

Duke Energy concurs with the B&WOG position and does not consider pressurizer clad cracking an applicable aging effect for the period of extended operation. However, the staff did not agree with this position and, for the reasons stated in the Safety Evaluation, established the requirement to inspect the pressurizer cladding as Open Item 1 in BAW-2244A. In accordance with this requirement, Duke will perform a one-time visual inspection (VT-3) of the pressurizer cladding at one Oconee Unit at or near the end of the current term of operation, as described in Section 4.3.7 of Exhibit A of the Application.

Now, the response to RAI 4.3.7-1 is provided.

The resolution requirement for a VT-3 examination is defined by ASME Section XI, IWA-2213, Table IWA-2210-1, and IWA-2320. The proposed pressurizer examination is consistent with the method used to examine the interior surfaces of the reactor vessel. Specifically, from ASME Section XI, IWB-3520.2, VT-3 examination of the interior surface of a reactor vessel is used to determine if the following relevant conditions require correction prior to continued service: (a) structural distortion or displacement of parts to the extent that the component function may be impaired; (b) loose, missing, cracked, or fractured parts, bolting, or fasteners; (c) foreign materials or accumulation of corrosion products; (d) corrosion or erosion that reduces the nominal section thickness by more than 5%; (e) wear of mating surfaces that may lead to loss of function; or, (f) structural degradation of interior attachments such that the original cross-sectional area is reduced by more than 5%. The suggested VT-3 visual examination would be used to detect cracking or corrosion products on the inside surface of the pressurizer. This method is consistent with the inspection method used at Haddam neck to detect cracks in the cladding. As reported in BAW-2244A, Appendix A, Response to RAI #8, a visual (camera) examination was used to identify cracking and corrosion products on the surface of the cladding at Haddam Neck. Ultrasonic examinations were then performed at Haddam Neck to determine if the visually identified indications extended into the base metal. A similar procedure would be followed for the Oconee inspection.

In addition, Examination Category B-B, "Pressure Retaining Welds in Vessels Other Than Reactor Vessels - Pressurizer", of ASME Boiler and Pressure Vessel Code, Section XI, IWB-2500-1 requires that a volumetric examination of selected pressurizer shell weld locations be conducted each inspection interval. The extent of the examinations is as follows. Both shell-to-head circumferential welds receive a volumetric inspection of essentially 100% of the weld length every inspection interval. One foot of each longitudinal weld intersecting the circumferential shell-to-head welds receives a volumetric inspection during the first inspection interval. The volumetric inspections of the welded joints include the heat-affected zone and weld metal adjacent to the clad interface, and any clad cracking that extends into the base metal at these locations would be detected. The longitudinal weld

that intersects the lower circumferential shell-to-head weld is adjacent to the lower heater bundle assembly, which is the general area where the indications were observed at Haddam Neck.

Any indication of cracking identified during the *Pressurizer Cladding Examination* will initiate the Problem Investigation Process (PIP). The PIP is a process governed by a nuclear generation department directive that will initiate an engineering evaluation of the identified condition. The PIP evaluation is designed to consider the need to conduct a root cause analysis and determine corrective actions, which may include actions to prevent recurrence. For this example, the PIP evaluation will determine the need for a root cause analysis, including the establishment of methods to determine the extent of cracking. The evaluation will also determine corrective actions that assure a degraded component condition has not or will not exceed the limit required for qualifying the component for further service.

Summary of Haddam Neck Event
As reported in BAW-2244A, a review of correspondence between the NRC and Haddam Neck indicated that there were cracks observed during a camera inspection of the cladding in 1990. The plant had been in operation for 22 years. The cracks were observed at the bottom of the pressurizer, in an area surrounding the strainer, which is positioned over the surge nozzle. The strainer cracks were intermittent in nature, and for the most part, located approximately 1-inch outboard from the edge of the fillet weld. (The nozzle is fillet welded to the stainless steel clad surface at the bottom head). In some areas the cracks were observed in the heat affected zone and the toe of the fillet weld.

Additional circumferential cracks were observed in the vertical shell sections adjoining the head. The most extensive cracking was observed in the vertical shell sections between the first and second support plate. The cracks diminished rapidly in number toward the top of the vessel. No cracks were observed in the top head except for small cracks in the area of the spray nozzle. Some staining was observed in the cracks, but there was no discernible evidence of rust buildup.

The ferrite content of the stainless cladding was reported to be an acceptable level of 6-9%. Radiography and ultrasonic testing (UT)was performed in an area between the first and second support plates, 360 degrees around the vessel. The radiography results confirmed that no linear or crack like indications were observed. Ultrasonic testing revealed 26 indications in the cladding in the vertical sections of the shell between the first and second support plate. Three indications extended into the base metal.

The flaws were reexamined during the 1991-1992 outage. No new suspect indications/flaws were found that would be considered to have penetrated beyond the base metal/clad interface and into the base metal.

The three suspect indications/flaws were reexamined more extensively using a UT-focused beam technique. Two of the three flaws did not exhibit crack like reflector responses. These two flaws were believed to be inclusions (i.e., UT reflectors not connected or associated with the clad cracking). The third suspect indication/flaw appeared to be an actual clad crack with extension into the base metal. Comparison of the 1990 UT results to those done in 1991 showed no increase in flaw depth. The through-clad crack was acceptable by evaluation without repair under the ASME B&PV Code Section XI flaw tolerance standards. Re-examinations on subsequent outages found no indications of further cracking or flaw growth.

RAI 4.3.7-2 (12/3/98A)
On page 2.4-27 of the application there appears to be an incorrect reference to the response to Renewal Applicant Action Item #4, of table 2.4-3. Report BAW-2243A is referred to instead of BAW-2244A. Please clarify.

Response to RAI 4.3.7-2
The Oconee-specific response to Action Item #4 on page 2.4-27 of Exhibit A of the Application should refer to BAW-2244A.

RAI 4.5-2 (12/3/98A)
Provide more details regarding the scope of the inspections. For example, is the scope of the Boric Acid Wastage Surveillance Program equivalent to the scope of the Inservice Inspection (ISI) Plan? If so, how are the "carbon steel and low-alloy items" and the "OTSG Upper Lateral Support Structure" listed in Table 3.4-1 (which do not appear to be part of the ISI program) included in the scope of the Boric Acid Wastage Surveillance Program?

Response to RAI 4.5-2
The scope of the *Boric Acid Wastage Surveillance Program* includes all Class 1 ISI components, selected Class 2 and Class 3 components that contain borated water, and components fabricated from carbon and low-alloy steel that are located in proximity to borated water systems. Although the scope of the *Boric Acid Wastage Surveillance Program*, as defined by GL 88-05, does not specifically include component supports, Oconee plant procedures require that borated water leakage be traced from its source to any and all affected components (including component supports). The *Oconee Inservice Inspection Program* complements the *Boric Acid Wastage Surveillance Program* at Oconee. For example, loss of material due to boric acid wastage would be identified when performing visual, surface, or volumetric examinations in accordance with the inservice inspection program.

RAI 4.10-1 (11/20/98G)
Regarding the content of Section 4.10, "Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetrations Inspection Program:"

In Section 4.10 to the License Renewal Application Duke indicated, in part, that the existing regulatory basis for the aging management program for Alloy 600 VHP nozzles is provided in the Duke response to Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations." In its response to GL 97-01, Duke indicated that it was a participant in the joint Babcock and Wilcox Owners Group (BWOG)/Nuclear Energy Institute (NEI) integrated program for assessing primary water stress corrosion cracking (PWSCC) in VHP nozzles to B&W designed VHP nozzles, and that this program was contained in BWOG Topical Report BAW-2301. On May 14, 1998, the NEI submitted an integrated "industry Histogram for Reactor Vessel Head Penetration" on behalf of PWR licensees participating in NEI's integrated assessment program for control rod drive mechanism (CRDM) penetration nozzles and other VHP nozzles in domestic PWR designs. The histogram ranked the CRDM penetration nozzles in "less than 5 year," "5 to 15 year," and "beyond 15 year" probabilities of failure categories. The CRDM penetration nozzles of Oconee have been designated as falling into the "less than 5 year" category and inspections of the Oconee Unit 2 CRDM penetration nozzles have been scheduled to be reinspected for a second time in the year 1999. However, the current integrated program and susceptibility assessment for the PWR industry is based on a 40-year (normal life) time frame. Provide the following information with respect to how the license renewal term for the Oconee units relates to the industry's integrated program for assessing domestic PWR VHPs:

a. Indicate whether Duke is committed to extending its participation in the BWOG integrated aging management program for VHP nozzles during the license renewal term for the Oconee units.

> i. If Duke is committed to extending its participation in the integrated program to the license renewal term, indicate how the integrated program will be used as the basis for proposing any further inspections of the VHP nozzles at Oconee Units 1, 2, and 3 during the extended license terms for the facilities.
>
> ii. If Duke is not committed to extending its participation in the integrated program to the license renewal term, describe what the basis (in addition to the inspections of the Oconee Unit 2 VHP nozzles in 1999) will be for assessing the potential for primary water stress corrosion cracking to exist in the Oconee VHP nozzles and for proposing any further inspections of the Oconee VHP nozzles during the extended license terms for the facilities.

Response RAI 4.10-1 (a)
Following Duke's initial response to Generic Letter 97-01 in July 1997, the industry program for Alloy 600 reactor vessel head penetrations was selected as one of the initial Issues Task Groups (ITG) in the newly formed Materials Reliability Project (MRP). The MRP was created to manage PWR materials issues and is similar in structure and function to the BWRVIP. In addition, a meeting was held on September 29, 1998, between the MRP Alloy 600 ITG and the NRC Staff. During the meeting, ITG member utilities (which includes Duke Energy) stated that they realized that Alloy 600 RPV head penetrations are going to be an issue as long as they are in service. The Alloy 600 ITG stated in a handout that their Goal and Regulatory Objectives are as follows:

ITG Goal:

"Develop a long-term management plan for the PWSCC of Alloy 600 Head Penetration in PWRs and achieve NRC acceptance of the plan"

MRP Regulatory Objectives:

1. "Achieve NRC acceptance of MRP Plan for long term management of PWSCC of Alloy 600 RPV Head Penetrations"

2. "Close out Generic Letter 97-01 for all utilities by June 1999"

3. "Periodic MRP-NRC meetings to provide update on inspection results and long term management of PWSCC of Alloy 600 RPV Head Penetrations"

4. "NRC to raise any future concerns to MRP"

Duke Energy is committed to extending its participation in the MRP/B&WOG integrated aging management program for reactor vessel head penetration nozzles during the period of extended operation for the Oconee units. If these groups were to disband, Duke Energy understands the need for and remains committed to a long-term program to ensure that the assumptions made in the Safety Evaluation remain valid during the period of extended operation.

Response RAI 4.10-1 (i)
Duke Energy, by participating in the MRP and B&WOG programs for Alloy 600 VHP, will stay abreast of industry activities, participate in the formation of research projects, obtain

updates to the model for Oconee, and take part in future meeting with the NRC. This participation will provide the bases for the timing of future inspections at Oconee, make sure that Oconee inspections are integrated into the industry program, and assure acceptance of the long term inspection plan for Oconee by the NRC. It is Duke Energy's understanding that neither the B&WOG nor the MRP has set a time limit on how long they will participate in managing Alloy 600 VHP PWSCC.

Response RAI 4.10-1 (ii)
By responding to RAI 4.10-1(i), a response to RAI 4.10-1(ii) is not necessary.

RAI 4.18-1 (11/20/98C)
Table 4-1 of BAW-2248 indicates that the vent valve retaining ring, vent valve bodies and the locking devices on the modified vent valve assembly do not require supplemental aging management program(s). Aging will be managed during the renewal term using ASME Code inspection methods. Since function of these components are affected by either a reduction of fracture toughness or stress corrosion cracking, what examination methodology will be utilized and are the surfaces of the components accessible for detecting cracks that could lead to failure of the components during the license renewal term? In addition, BAW-2251 states that the aging management elements of the reactor internals vent valves are contained in plant-specific technical specifications for ANO-1 and TMI-1 (see page 4-3 of report). In accordance with 10 CFR 54.22, provide the justification for whether changes or additions to the technical specifications are necessary to manage aging effects of the vent valve assembly during the license renewal term for Oconee.

Response to RAI 4.18-1
The vent valve bodies are fabricated from cast austenitic stainless steel. As such, the aging management programs that are applicable for reduction of fracture toughness for the vent valve bodies are the ASME Section XI ISI program and the *Pump and Valve In-Service Test Program* for the Oconee units. These programs will be further supplemented by the extension of the CASS evaluation procedures described in Section 4.18.2.2 of Exhibit A of the Application.

The vent valve retaining rings are fabricated from precipitation-hardening stainless steel materials and are potentially susceptible to reduction of fracture toughness. BAW-2248 lists the ASME Section XI ISI program as an applicable program to manage this aging effect. In addition, the vent valves are tested and inspected each refueling outage through the Pump and Valve In-Service Test Program for the Oconee units. This supplemental program along with the ASME Section XI ISI will manage reduction of fracture toughness of the retaining rings during the period of extended operation.

Page 4-3 of BAW-2248 states that the aging management elements of the reactor internals vent valves are contained in the *Pump and Valve In-Service Test Program* per ASME Section XI for Oconee Units 1, 2, and 3. The testing requirements of the Oconee internals vent valves are not contained in Technical Specifications, therefore, no changes or additions are required in order to comply with §54.22.

RAI 4.18-3 (12/2/98D)
Section 4.18 "Inservice Inspection Plan" states that the period of extended operation will contain the fifth and the sixth inspection intervals. However, the ASME Code, Section XI, addresses up to the fourth inspection interval. Therefore, how will the inspection period, percentage of examination during each period, the extent and frequency of examination be tailored to benefit timely detection of aging effects during the fifth and the sixth inspection intervals to maintain intended function of the components during the extended term of operation? Also, provide your criteria for selection of weld inspection locations for Examination Category B-J "Pressure Retaining Welds in Piping" during the extended term of operation.

Response to RAI 4.18-3
In accordance with ASME Boiler and Pressure Vessel Code, Section XI, IWB-2400, Oconee may implement either Inspection Program A or Program B. Inspection Programs A is not limited to four inspection intervals. As specified in IWB-2411(c), following the completion of Program A after 40 years, successive inspection intervals shall follow the 10-year inspection interval of Program B. Program B simply lists the 1st inspection interval followed by successive intervals and does not limit the inspections to a defined number of intervals. The extent and frequency of examinations are contained in Table IWB-2500-1 of Section XI of the ASME Boiler and Pressure Vessel Code.

In addition, the staff in its approval of both the B&W Owners Group reports BAW-2243A and BAW-2244A made findings that indicated the acceptability of the 1989 Edition of the ASME Code Section XI for the period of extended operation. Thus, Duke Energy concludes that the current editions of ASME Boiler and Pressure Vessel Code, Section XI examinations are not limited to 40 years.

The inspection period, percentage of examination during each period, the extent and frequency of examination during the fifth and the sixth inspection intervals will be in accordance with the ASME Code Section XI Edition and addenda, as well as modifications and limitations specified in §50.55a.

Examination Category B-J—From BAW-2243A
At present, Oconee selects Examination Category B-J pipe welds for inspection based upon 10 CFR 50.55a(b)(2)(ii), available stress information as applied to the 1989 Edition of ASME Section XI, and previous examinations performed. Therefore, Oconee applies a combination of the 1974 and 1989 editions of the ASME Code for Examination Category B-J when selecting pipe welds for inspection. For example, all terminal end welds connected to vessels are examined, and the higher stressed welds (i.e., usage factor greater than 0.4 or primary plus secondary stress greater then 2.4 Sm) were generally selected for

examination when detailed stress reports were available. As Oconee completes stress reports for the Class 1 piping attached to the main coolant piping, welds that meet the Examination Category B-J selection criteria will be added to the list of inspections. In addition, Duke is also studying the potential benefits of risk-based inspection and may opt to pursue implementation of Risk-Informed Inservice Inspection as an alternative plan based on the evaluation of the safety and economic benefits. For the extended period of operation, Oconee will comply with the industry and regulatory requirements in existence, regardless of whether Risk-Informed Inservice Inspection is implemented.

RAI 4.18-4 12/2/98D)
What is the aging management program for the flow stabilizers inside the reactor pressure vessel (Refer open item 4.2(2) in the topical report BAW-2251)?

Response to RAI 4.18-4
RAI 4.18-4 is redundant to RAI 3.4.5-4. Please see the Oconee-specific response to Open Item Number 2 contained in RAI Response Table 3.4.5-1.

RAI 4.22-1 (11/20/98D)
Section 4.22 of the LRA indicates that aging effects of the HPI nozzles, thermal sleeves, and attached RCS piping will be managed by the "Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System." For each component in the program, identify the method of inspection and the frequency of inspection to be used during the license renewal term.

The Corrective Action in Section 4.22 of the LRA indicates "flaws in welds or base metal which cannot be accepted based on either geometry screening or the Fracture Mechanics Analysis methods of the ASME Code Section XI are corrected by repair or replacement." In order to perform a Fracture Mechanics analysis, the stresses that cause the crack to grow must be known. Based on the causes of crack growth in HPI nozzles, thermal sleeves, and attached RCS piping, are the stresses that cause the crack to grow known? If they are not known, how does it impact the corrective action section of the LRA?

Response to RAI 4.22-1

As clarified in a telephone call held on January 21, 1999 between NRC and Duke, a sample of the detailed inspection plans is appropriate to illustrate the inspections to be performed. The following table is provided to show typical inspections to be performed for the High Pressure Injection System nozzles and connected piping. The Table is for loop 1A1; the other loops on Unit 1 and the other two Oconee units are similar.

Weld: Component	Reason	Insp. Type	Insp. Procedure (5)	Insp. Frequency ≥ 5th Interval
Nozzle Inside Radius	GL 85-20 (2)	UT	NDE-690	≥ 3/ interval
BW (1): Nozzle Body to Safe End	ASME XI (3), Dissimilar	PT	NDE-35	1/interval
	GL 85-20	UT	NDE-610	≥ 3/ interval
Safe End Base Metal	GL 85-20	UT	NDE-960	≥ 3/ interval
Thermal Sleeve along entire length of rolled in portion within Safe End	GL 85-20	RT	NDE-105	≥ 3/ interval
BW: Safe End to Pipe	ASME XI, Stress	PT	NDE-35	1/interval
BW: Safe End to Pipe & Pipe Base Metal to Valve (1HP-127)	GL 85-20 & IEB 88-08 (4)	UT	NDE-960	≥ 3/ interval
BW: Pipe to Valve (1HP-127)	GL 85-20 & IEB 88-08	UT	NDE-960	≥ 3/ interval
BW: Valve (1HP-127) to Valve (1HP-487)	IEB 88-08	UT	NDE-600	3/ interval
BW: Valve (1HP-487) to Pipe	IEB 88-08	UT	NDE-600	3/ interval
BW: Pipe to Elbow	IEB 88-08	UT	NDE-600	3/ interval
BW: Elbow to Pipe	IEB 88-08	UT	NDE-600	3/ interval

(1) Butt Weld.
(2) Inspection is being performed to meet the commitments of Generic Letter 85-20, Resolution of Generic Issue 69; High Pressure Injection/Make-up Nozzle Cracking in Babcock and Wilcox Plants.
(3) ASME Code inspections are being listed here for information only. Code inspections commitments are discussed in Section 4.18 of Exhibit A of the Application.
(4) Inspection is being performed to meet the commitments or requirements of Inspection and Enforcement Bulletin 88-08, Thermal Stresses in Piping Connected to the Reactor Coolant System.
(5) Ultrasonic inspections shall meet the requirements of either Appendix VIII of Section XI of 1992 w/1993 addenda ASME, or mockups containing thermal fatigue cracks will be used. The commitments of Oconee letter from Mr. W. R. McCollum, Jr. to U.S. Nuclear Regulatory Commission of January 7, 1998 on Oconee Nuclear Site, Docket Nos. 50-269, -270, -287, Inservice Inspection Program, Third Yen-Year ISI Interval, GL 85-20 Supplemental Information [in answer to the NRC letter from David E. LaBarge to Mr. W. R. McCollum of October 23, 1997, High Pressure Injection System Augmented Inservice Inspection Program - Oconee Nuclear Station Units 1, 2, and 3 (TAC No. M98454)] will continue to apply.

With regard to the use of fracture mechanics analysis for the acceptance of flaws and the need to know the stresses, since the location of any possible future discoveries of inservice inspection indications are not known at this time, and the detailed stresses are not known at every location, it cannot be determined if the detailed stresses are or will be known at those points. Further, the mechanisms that caused the cracking experienced in Unit 2 in 1997 (See Section 4.22.2 of Exhibit of the Application for additional discussion of operating experience) will not necessarily be the same to cause any future cracking. The generation of the required stresses will be a part of the fracture mechanics analysis efforts to be employed at that time. They would be conservatively generated from the applicable design and actual service duty transient events. If at that time generation of these stresses is considered impractical or for other reasons fracture mechanics analysis is not considered a viable option, then repair or replacement will be pursued.

RAI 4.26-1 (12/3/98A)
Discuss the differences between the subject aging management program and that provided by Oconee's Improved Technical Specification 5.5.10. For example, comprehensively managing aging effects for steam generators requires more than just an eddy current test procedure. Specifically, there are requirements for determining what type of technique is to be applied in what region of the steam generator, what type of training program is to be given to eddy current test personnel, and what guidance is developed on how to disposition eddy current test results. In addition, industry guidelines are constantly being updated to reflect the state-of-the-art in eddy current testing. Discuss how this type of information, among other things, is addressed in the subject aging management program.

Response to RAI 4.26-1
The *Steam Generator Tube Surveillance Program* is identical to the program described in Section 5.5.10 of the Oconee Improved Technical Specifications. This program fully complies with all the requirements of NEI 97-06, "Steam Generator Program Guidelines." Compliance with these guidelines ensures that the steam generator inspection and repair program fully meets the continuing requirements for acceptable steam generator performance in areas of tube structural integrity, accident leakage integrity, and operational leakage integrity. The program includes requirements for inspection and monitoring of tube integrity, secondary side internal structures, bolted closures and shell integrity. Duke Energy will continue to evaluate and implement new inspection techniques through compliance with the EPRI standards referenced in NEI 97-06, which include using qualified inspection techniques for specific types of tube degradation.

Set # 04
February 17, 1999

RAI 5.1-1 (12/3/98B)
Duke did not identify the following as time-limited aging analyses (TLAAs) for the Oconee Units:

- Metal corrosion allowance
- Inservice local metal containment corrosion
- Reactor vessel pressure-temperature limit analysis and low temperature overpressure protection analysis

For each of these areas, discuss whether the TLAA is applicable to the Oconee units or provide the basis if it is not applicable. For each of those analyses that are considered applicable, discuss whether the TLAA meets the definition of a TLAA in 10 CFR 54.3(a) or provide the basis if it does not meet this definition. For those TLAAs that are determined to be applicable to the Oconee units and meet the definition of a TLAA in 10 CFR 54.3(a) provide the demonstration required by 10 CFR 54.21(c)(1).

Response to RAI 5.1-1
The process used to identify the Oconee specific time-limited aging analyses is consistent with the guidance provided in NEI 95-10, Revision 0, Chapter 5.

In order to provide reasonable assurance that the Oconee time-limited aging analyses have been identified, searches of several document sets were conducted. Duke believes that the multiple searches of multiple source documents provide reasonable assurance that the Oconee time-limited aging analyses have been identified.

Oconee-specific source documents that were reviewed for time-limited aging analyses include the Oconee licensing correspondence file, the Oconee Updated Final Safety Analysis (UFSAR), BWNT Topical Reports referenced in both correspondence and the UFSAR, and ASME Section XI Summary Reports. All Oconee time-limited aging analyses were identified in one or more of these documents.

Additional assurance in completeness of the resultant list of Oconee-specific time-limited aging analyses was obtained by reviewing several generic source documents. Specifically, in addition to the review of Oconee-specific documents, reviews were performed on several documents that are generically applicable to all pressurized water reactors. The generic source documents reviewed included the Standard Review Plan, various codes and standards, and certain NRC generic regulatory compliance documents including Bulletins, Generic Letters, Regulatory Guides, and 10 CFR Part 50 and its Appendices. The review of

generic source documents confirmed the results from the review of Oconee-specific source documents.

The information developed from the review of both Oconee-specific source documents and generic source documents was reviewed to determine which calculations and analyses meet all six criteria of §54.3. The analyses and calculations that meet all six criteria were identified as Oconee-specific time-limited aging analyses. Duke believes that this process provides reasonable assurance that the Oconee-specific time-limited aging analyses have been identified.

With respect to the three topics identified in RAI 5.1-1, the following additional information is provided:

Metal corrosion allowance – Duke Energy assumes that the concern of metal corrosion allowance as a time-limited aging analysis applies only to mechanical piping systems. Duke is not aware of any other potential application. In order for metal corrosion allowance to be a time-limited aging analysis, there must be an assumption of a rate of loss of material (e.g., mils per year) within the calculation or analysis. This rate of loss of material would then need to be multiplied by the current operating term (e.g., 40 years) and the results utilized to determine the metal wall thickness in order to be considered a time-limited aging analysis. Corrosion allowances are discussed in the design codes and are left to the judgement of the designer during the design of piping systems. The extent to which corrosion allowances are utilized in piping systems is very much dependent on the architect-engineers who designed the systems.

The design of Oconee metal piping was reviewed to determine whether metal corrosion allowance could be considered a time-limited aging analysis. Oconee piping specifications were reviewed and knowledgeable engineers were interviewed to determine if the Oconee pipe design considered explicit time-limited corrosion allowances. This review did not identify any calculations or analyses that specified metal corrosion allowances. Thus, metal corrosion allowance is not considered a time-limited aging analysis for Oconee.

However, loss of material has been identified as an applicable aging effect for several mechanical systems as discussed in Section 3.5 of Exhibit A of the Application. Although this topic does not meet the definition of a time-limited aging analysis as contained in §54.3, the loss of material in piping systems is being effectively managed by the following programs at Oconee which are described in Chapter 4 of Exhibit A of the Application:

- *Boric Acid Wastage Surveillance Program*
- *Fire Water System Test (part of the Fire Protection Program)*

- *Heat Exchanger Performance Testing Activities*
- *Piping Erosion/Corrosion Program*
- *Service Water Piping Corrosion Program*
- *Steam Generator Tube Surveillance Program*
- *System Performance Testing Activities*

Inservice local metal containment corrosion [allowance] – A search of Oconee engineering documents did not identify any calculations or analyses that specified a corrosion allowance for the Containment liner plate. Pursuant to §54.3, any time-limited aging analysis must, at a minimum, be a calculation or analysis. Thus, this topic (Inservice local metal containment corrosion [allowance]) cannot be considered as a time-limited aging analysis for Oconee.

However, as noted in our response to RAI 3.3-12 provided by letter dated January 14, 1998, the thickness of the liner plate is sufficient to allow some loss of material to occur without a loss of the essentially leak tight barrier. The liner plate is coated and periodic inspections will be conducted during the period of extended operation in accordance with the inspection requirements in Subsection IWE of ASME Boiler and Pressure Vessel Code Section XI as provided in the Containment Inservice Inspection Plan which is described in Section 4.8 of Exhibit A of the Application.

Although this topic does not meet the definition of a time-limited aging analysis as contained in §54.3, the aging effect of concern (loss of material) is being effectively managed by the *Containment Inservice Inspection Plan* which is described in Section 4.8 of Exhibit A of the Application.

Reactor vessel pressure-temperature limit analysis and low temperature overpressure protection analysis –
These analyses exist but they fail to meet the following criterion contained in §54.3:

> Time-limited aging analyses, for the purposes of this part, are those licensee calculations and analyses that:
> (3) Involve time-limited assumptions defined by the current operating term, for example, 40 years;

These analyses utilize a number of input parameters including reactor vessel beltline material properties and projected fluence values and are valid for only a limited number of effective-full power years which are substantially less than the current operating term. Because the materials data must be obtained as the plant is operating, the materials and fluence data for the end of life is not available until later in the licensed life of the plant.

The reactor vessel pressure-temperature limit analysis and low temperature overpressure protection analysis provide the bases for curves that are part of the Oconee technical specifications and are required to be revised and updated prior to expiration. For example, by letter dated October 15, 1998 Duke submitted a proposed technical specification revision to incorporate pressure-temperature operating curves for each Oconee nuclear unit that are effective for the first 26 effective-full power years. As more materials data becomes available in the future, proposed revisions to these curves will be submitted for NRC approval. These operating curves are currently being developed and maintained in accordance the *Reactor Vessel Integrity Program* as described in Section 4.24 of Exhibit A of the Application.

Although this topic does not meet the definition of a time-limited aging analysis as contained in §54.3, the aging effect is being effectively managed by the existing *Reactor Vessel Integrity Program* which is described in Section 4.24 of Exhibit A of the Application.

RAI 5.4.1-1 (11/24/98A)
Section 5.4 of the license renewal application indicates that B&W Owners Group Report BAW-2243A, Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping, June 1996, identified leak-before-break and high energy line break postulation based on fatigue cumulative usage factor (CUF>0.1) as generically applicable time-limited aging analyses (TLAAs). However, the application indicates that, "the review conducted of Oconee documentation determined that neither the leak-before-break analyses nor the cumulative usage factor (CUF>0.1) analyses are time-limited aging analyses for Oconee." Provide the bases for this conclusion. Describe the documentation that was reviewed. Include a discussion of the applicability of the definition of TLAA in 10 CFR 54.3 to leak-before-break and high energy line break postulation at Oconee.

Response to RAI 5.4.1-1
The process that was used to determine the TLAA that are applicable to the Oconee Nuclear Station is described in Section 5.2 of Exhibit A of the Application. Oconee findings relative to high energy line break and leak-before break are summarized below.

High Energy Line Break
Requirements for the determination of high-energy line break locations and dynamic effects associated with the postulated rupture Class 1 piping where cumulative usage factors exceed 0.10 are contained in the Standard Review Plan (SRP), NUREG-75/087, Section 3.6.2. These SRP requirements supersede those that are specified in Regulatory Guide 1.46 entitled "Protection Against Pipe Whip Inside Containment."

Because neither the SRP nor Regulatory Guide 1.46 were utilized in the design of Oconee, the criteria to determine postulated break locations for Class 1 piping where cumulative usage factors exceed 0.10 is not a TLAA for Oconee. The design of Oconee predates these two regulatory guidance documents.

At Oconee, the design of the pipe whip restraints generally considered postulated pipe failures at all locations for all piping greater than ¾-inch nominal pipe size (NPS). The locations chosen for pipe whip restraints at Oconee were not based on cumulative usage factor. In addition, pipe whip restraints are no longer required for Reactor Coolant System piping of NPS 28-inch and larger owing to acceptance of the leak-before-break evaluations reported in BAW-1847.

Leak-Before-Break

The successful application of Leak-Before-Break (LBB) to the Oconee Reactor Coolant System main coolant piping is described in B&WOG topical report entitled, "The B&W Owners Group Leak-Before-Break Evaluation of Margins Against Full Break for RCS Primary Piping of B&W Designed NSSS," BAW-1847, Revision 1, September 1985. This report provides the technical basis for evaluating postulated flaw growth in the main Reactor Coolant System piping under normal plus faulted loading conditions and was approved by the NRC for the current term of operation. The TLAA in BAW-1847, Revision 1, include fatigue flaw growth and the qualitative assessment of thermal aging of cast austenitic stainless steel reactor coolant pump inlet and exit nozzles.

At the time of the preparation of the Application for Renewed Operating Licenses for Oconee Nuclear Station, Duke did not identify leak-before-break as a TLAA since BAW-1847, Revision 1, had not been referenced in any of the source documents listed in Section 5.2 of Exhibit A of the Application. However, the resolution of a recently discovered inconsistency between the Mark-B fuel assembly horizontal faulted condition analyses and ECCS calculations required the use of leak-before-break to resolve the issue. Therefore, the leak-before-break analysis was recently incorporated in the Oconee current licensing basis through the UFSAR update December 31, 1997 and transmitted to NRC in July 1998. Leak-before-break was subsequently identified as a TLAA for the Oconee units. Fatigue flaw growth and thermal aging of cast austenitic stainless steel reactor coolant pump inlet and exit nozzles are discussed below.

Fatigue Flaw Growth

The leak-before-break analysis reported in BAW-1847, Revision 1, was performed in accordance with the guidance provided in Section 5.2, Item (d), of NUREG 1061, Volume 3. Specifically, a surface flaw was postulated at selected location(s) of the piping system (i.e., highest stress coincident with the lower bound of the material properties for base material, weldments and safe-ends), and a fatigue crack growth analysis for the postulated flaw was then performed to demonstrate that the crack would not grow significantly during the service life of the component.

Subsequent to the approval of BAW-1847, Revision 1, the NRC issued Standard Review Plan (SRP) 3.6.3 in August 1987, which now forms the basis for NRC review of leak-before-break submittals. The new SRP 3.6.3 eliminated the requirement to perform a fatigue flaw growth analysis. Comparing SRP 3.6.3 requirements to the BAW-1847, Revision 1, results shows that BAW-1847, Revision 1, meets all requirements of SRP 3.6.3 and that the flaw growth analysis information in BAW-1847, Revision 1, is now extraneous. Since a fatigue flaw growth analysis is no longer required for justification of LBB, it is concluded that the fatigue flaw growth analysis reported in BAW-1847, Revision 1, is not required to

demonstrate the applicability of leak-before-break for Reactor Coolant System piping for the period of extended operation.

Thermal Aging of Cast Austenitic Stainless Steel Reactor Coolant Pump Suction and Discharge Nozzles

The susceptibility of the Reactor Coolant System main coolant piping to thermal aging was qualitatively addressed in Section 3.3.4.3 of BAW-1847, Revision 1. The main coolant piping material that is susceptible to thermal aging is the cast austenitic stainless steel (CASS) portion of the welded joint that connects the CASS reactor coolant pump suction and discharge nozzles to the 28-inch wrought stainless steel transition pieces. Limited data regarding thermal aging of CASS material was available at the time of the preparation of the B&WOG leak-before-break report. Specifically, owing to the lack of test data, the values of fracture toughness for aged cast austenitic stainless steel were assumed to be bounded by the ferritic piping and ferritic weldments. Since the publication of BAW-1847, Revision 1, a significant amount of data has been obtained regarding thermal aging of CASS materials.

Test data obtained by Argon National Laboratory (ANL) [O. K. Chopra and W. J. Shack, "Assessment of Thermal Embrittlement of Cast Stainless Steels," NUREG/CR-6177, U.S. Nuclear Regulatory Commission, Washington DC, May 1994], indicate that prolonged exposure of CASS to reactor coolant operating temperatures can lead to reduction of fracture toughness by thermal embrittlement. The fracture toughness curves for the ferritic base metal and ferritic weld metals used in the Reactor Coolant System piping leak-before-break analysis were compared to the lower-bound fracture toughness curves of Oconee reactor coolant pump CASS materials (i.e., statically cast CF8 and CF8M) from the ANL report. The fracture toughness curve of the lower-bound CASS material is below the fracture toughness curves used in the Reactor Coolant System piping leak-before-break analysis. Therefore, the assumption in BAW-1847, Revision 1, that the fracture toughness of the ferritic piping and ferritic weldments bounds the fracture toughness of CASS materials cannot be supported.

A flaw stability analysis was performed using the lower-bound CASS fracture toughness curves from the ANL report cited above to show acceptability of leak-before-break for the Reactor Coolant System main coolant piping for the period of extended operation. The most limiting material and location used in the Reactor Coolant System piping leak-before-break analysis (i.e., BAW-1847) was determined to be the base metal material of the straight section of the 28-inch cold leg pipe. Both the suction and discharge nozzles of the reactor coolant pump casings are attached to the 28-inch cold leg pipes and have similar geometry and loading applied to them as the limiting location used for the leak-before-break analysis. The discharge and suction nozzles of the reactor coolant pump casings were evaluated for leak-before-break using lower-bound CASS fracture toughness properties.

Bounding 10 gpm leakage crack sizes for the reactor coolant pump suction and discharge nozzle were determined using a methodology that is consistent with that reported in BAW-1847, Revision 1. The leakage crack length (twice the leakage flaw size) for the suction nozzle was determined to be 8.62 inches and the leakage crack length for the discharge nozzle was determined to be 8.86 inches. A flaw stability analysis for the reactor coolant pump inlet and exit nozzles was conducted, and the discharge nozzle was found to be limiting. The maximum applied J value at the discharge nozzle, for the 10 gpm leakage flaw size, was determined to be 0.510 kips/in. The margin on flaw size was determined to be 2.4, which is greater than the required margin of 2 in accordance with SRP 3.6.3.

Summary-LBB for the Period of Extended Operation
In summary, with the exclusion of the fatigue flaw growth analysis requirements in SRP 3.6.3, demonstration that the fatigue flaw growth analysis reported in BAW-1847, Revision 1 remains valid for the period of extended operation is no longer required. The remainder of the generic leak-before-break analysis for the B&W operating plants reported in BAW-1847, Revision 1, remains valid for the period of extended operation with the exception of the assessment of reduction of fracture toughness by thermal aging of cast austenitic stainless steel reactor coolant pump nozzles. Reduction of fracture toughness of the reactor coolant pump nozzles was determined to be acceptable for the period of extended operation through the flaw stability analysis described above.

RAI 5.4.1-2 (11/24/98A)
Section 5.4.1.1.2 of the license renewal application identifies locations within the B&W scope of supply that require further evaluation for thermal fatigue. The locations that require further evaluation include the reactor vessel studs for all three units, the pressurizer spray line for Unit 3, and the Emergency Feedwater System nozzle for Unit 3. Describe the planned evaluation of these components. Provide a schedule for the completion of this evaluation. Discuss your compliance with the requirements in 10 CFR 54.21(c)(1) for these items.

Response to RAI 5.4.1-2
Reactor Vessel Studs: These items were targeted for more evaluation based on an over-conservative assumption in the number of cycles. This assumption has been revised and these items are now being managed through the *Thermal Fatigue Management Program* that monitors plant cycles. (See also the response to RAI 5.4.1-5 for additional information on the *Thermal Fatigue Management Program.*)

Unit 3 Pressurizer Spray Line: This item was targeted for more evaluation based on the Unit 3 analysis being inconsistent with Units 1 and 2 which precluded convenient screening at the same time as the other Class 1 components. Re-analysis has been completed and this item is now being managed through the *Thermal Fatigue Management Program* that monitors plant cycles. (See also the response to RAI 5.4.1-5 for additional information on the Thermal Fatigue Management Program.)

Unit 3 EFW nozzle: This item was targeted for more evaluation based on the Unit 3 analysis being inconsistent with Units 1 and 2 which precluded convenient screening at the same time as the other fatigue sensitive components. Re-analysis is expected to be complete August 1, 1999 and when complete this item will be managed through the *Thermal Fatigue Management Program* that monitors plant cycles. (See also the response to RAI 5.4.1-5 for additional information on the Thermal Fatigue Management Program.)

Compliance with §54.21(c)(1) is through option (iii): "The effects of aging on the intended function(s) will be adequately managed for the period of extended operation."

RAI 5.4.1-3 (11/24/98A)
Section 5.4.1.1.3 of the license renewal application indicates that the reactor coolant loop attached piping was originally analyzed to USAS B31.7, Class II standards. The application further indicates that the fatigue evaluation of this piping to Class I standards is currently underway. Provide the schedule for the completion of these analyses. Discuss your compliance with the requirements in 10 CFR 54.21(c)(1) for these items.

Response to RAI 5.4.1-3
The schedule for completion was communicated in Reference 5.4-7 of Exhibit A of the Application and accepted via NRC letter reference 5.4-8. Overall completion is scheduled for August 31, 1999 and when complete these items will be managed through the *Thermal Fatigue Management Program* that monitors plant cycles. (See also the response to RAI 5.4.1-5 for additional information on the Thermal Fatigue Management Program.)

Compliance with §54.21(c)(1) is through option (iii): "The effects of aging on the intended function(s) will be adequately managed for the period of extended operation."

RAI 5.4.1-4 (11/24/98A)
Section 5.4.1.1.5 of the license renewal application addresses NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems." The application indicates that a supplemental response to the bulletin will be provided by July 1, 2000. Discuss your compliance with the requirements in 10 CFR 54.21(c)(1) considering the ongoing effort regarding NRC Bulletin 88-08.

Response to RAI 5.4.1-4:
The supplemental response to Bulletin 88-08 was intended to provide resolution to thermal stratification / back flow phenomena discovered during investigation of the Unit 2 High Pressure Injection system piping to nozzle safe end weld leak that occurred in the spring of 1997. Oconee provided the first supplemental response to the Bulletin on February 26, 1998 [Reference 5.4-16 of Exhibit A of the Application]. Oconee provided a six-part plan that addresses the thermal stratification / back flow phenomena for the high pressure injection connection to the Reactor Coolant System in that response. Excerpts of the plan include the determination of the cause of the thermal stratification / back flow phenomena, configuration and operational changes necessary to prevent the phenomena, and monitoring of the affected lines to determine if the configuration and operational changes have been effective in eliminating the phenomena. The final supplemental response, to be provided July 1, 2000, will provide the results of the plan.

The forgoing plan and resolution is an example of the work described in the *Thermal Fatigue Management Program*. This program intends to manage time limited aging aspects of the identified components and thus § 54.21(c)(1) compliance is through option (iii), "The effects of aging on the intended function(s) will be adequately managed for the period of extended operation."

RAI 5.4.1-5 (11/24/98A)
Section 5.4.1.3 of the license renewal application describes the Thermal Fatigue Management Program. The application indicates that the program, "tracks actual plant thermal cycles for those components that contain design features that have explicit design basis transient cycle assumptions in order to assure the continued validity of the component design basis." Provide a summary of the Thermal Fatigue Management Program that addresses the elements listed below. The summary should also include a discussion of the bases for each of these elements.

(a) Scope of the program that includes the specific structures and components subject to fatigue monitoring including the location monitored for each structure or component;

(b) Preventive actions that will be used to mitigate or prevent fatigue degradation;

(c) Parameter(s) to be monitored and the monitoring device(s) at each location monitored by the program;

(d) Assurance that detection of fatigue degradation will occur before loss of the structure or component intended functions;

(e) Program monitoring, trending, inspection technique, testing frequency, and sample size to ensure structure and component intended functions;

(f) The method used to compare the monitored data to the fatigue analysis of record;

(g) Acceptance criteria to ensure structures and components can perform intended functions; and

(h) Operating experience from similar programs or inspection techniques used by Duke or the industry.

Response to RAI 5.4.1-5
Duke is providing the following summary of the Oconee *Thermal Fatigue Management Program* prior to providing responses to the specific requests for additional information contain in this RAI. The purpose of the Oconee *Thermal Fatigue Management Program* is to track actual plant thermal cycles for those components that contain design features that have explicit design basis transient cycle assumptions in order to assure the continued validity of the component design basis.

The component scope requiring design thermal cycle limit confirmation for license renewal is:

(1) Reactor Coolant System components (including piping connected to the Reactor Coolant System falling under the purview of IE Bulletins 88-11 and 88-08).
(2) Components falling within the Oconee ISI Program that contain flaws detected during ISI that exceeded acceptance standards, but were shown to be acceptable by analysis.

From continual monitoring of plant operating conditions, the responsible engineer will discover plant conditions that meet the definition of a transient cycle defined by this program. Upon discovery of each transient cycle required to be documented by the program, the responsible engineer will tabulate the cycle count and enter it into a database. The database information allows a comparison of the accumulated cycles to the overall allowable

cycles required to be documented. Note that not all transient events require documenting since some analysis categories assumed values that far exceed what can be accomplished physically within 60 years of plant operation and some transient events will result in negligible fatigue. If a transient cycle count approaches or exceeds the allowable design limit, corrective action steps are taken.

The program acceptance criterion is to maintain the actual thermal cycle transient count within overall allowable limits. Should an allowable limit for a transient cycle set be approached or exceeded, the program requires that the responsible engineer identify the issue to the appropriate Oconee engineering group(s) for resolution. The Oconee Problem Investigation Process (PIP) would be followed for resolution.

Now, responses to the specific requests for additional information are provided.

(a) Scope of the program that includes the specific structures and components subject to fatigue monitoring including the location monitored for each structure or component;

The Oconee *Thermal Fatigue Management Program* is an event monitoring program, not a fatigue monitoring program. There is no location specific monitoring. As noted in Section 5.4.1.3 of Exhibit A of the Application, the component scope is (1) Reactor Coolant System components and (2) components for which inservice inspections are being accepted based on fatigue crack growth.

(b) Preventive actions that will be used to mitigate or prevent fatigue degradation;

Corrective actions are taken if the number of events is expected to exceed the limits of design within a manageable time period. A manageable time period is the time needed to complete actions to ensure the affected components stay within acceptable limits. Corrective actions may include such options as component re-analysis, transient re-classification, more sophisticated monitoring, repair, or replacement.

(c) Parameter(s) to be monitored and the monitoring device(s) at each location monitored by the program;

Parameters are not monitored; please see the response to Item (a), above.

(d) Assurance that detection of fatigue degradation will occur before loss of the structure or component intended functions;

Please see the response to Item (b), above.

(e) Program monitoring, trending, inspection technique, testing frequency, and sample size to ensure structure and component intended functions;

The responsible engineer on a continual basis documents transient cycles. Actual cycles are logged following discovery of each plant transient that is required to be tracked and managed. Please see also responses to Items (a) and (b), above.

(f) The method used to compare the monitored data to the fatigue analysis of record;
Thermal cycle logging is performed following the method described in an engineering workplace procedure, which includes documentation of Allowable Operating Transient Cycles (AOTC). This document specifies those design transients that must be identified and counted when they occur. The engineer responsible for maintaining the AOTC log reviews data available from sources such as the plant Operator Aid Computer, Control Room logs, and plant schedules to determine if a unit has experienced a transient that requires logging. For those events that are considered fatigue significant, the document specifies appropriate parameters such as minimum/maximum temperature limits and rates of temperature change that are assumed in the analysis. The logging process captures these values and reviews them to verify that the parameters do not exceed values used in the analysis.

The numbers of cycles logged for each significant transient is compared to the number of cycles evaluated in the fatigue analysis. If it the projected number of cycles for a particular transient indicates that the number evaluated will be exceeded, measures are taken to reevaluate or replace the limiting components so that the number of logged cycles will not exceed the number of analyzed cycles. In this manner, the cumulative usage factor (CUF) of components will be maintained less than 1.00.

(g) Acceptance criteria to ensure structures and components can perform intended functions;
Please see the response to Item (b), above.

(h) Operating experience from similar programs or inspection techniques used by Duke or the industry.
While not identical, Oconee *Thermal Fatigue Management Program* is similar to that used at TMI which has been reviewed and found acceptable by the NRC (Reference NRC Inspection No. 50-289/94-03).

Set # 04
February 17, 1999

RAI 5.4.2-1 (11/20/98D)
It is stated in the LRA that information in Tables 5.4-1, 5.4-2 and 5.4-3, "Evaluation of Reactor Vessel Pressurized Thermal Shock Toughness Properties at 48 EFPY," supersedes the information presented in Appendix A to Babcock & Wilcox Owners Group (B&WOG) Topical Report BAW-2251. Appendix A to the report, in part, includes the RT_{PTS} calculations for the Oconee beltline materials that are calculated using reactor pressure vessel surveillance data. However, no corresponding information was provided in Section 5.4.2 of the LRA nor in corresponding tables referenced in the section. Since the submittal of the Oconee LRA, the B&WOG has submitted additional best-estimate chemistry and surveillance data information for the beltline materials in B&W fabricated vessels (Topical Report BAW-2325). The data in LRA Tables 5.4-1, 5.4-2 and 5.4-3 are different from the data reported for the beltline materials in Topical Report BAW-2325.

a. Provide revised Pressurized Thermal Shock Tables (Tables 5.4-1, 5.4-2 and 5.4-3) based on the most recent beltline and surveillance data for beltline materials in Oconee Units 1, 2, and 3.

b. Provide the appropriate surveillance data and calculations used in the RT_{PTS} assessments of beltline materials which use surveillance data for calculating chemistry factors of the materials. Include application of the ratio procedure in Regulatory Guide (RG) 1.99, Revision 2 where appropriate (e.g., for beltline welds represented in the surveillance programs). Identify the sources of all surveillance data used in the assessments. Provide an assessment of which surveillance data points meet the credibility criteria of RG 1.99, Revision 2.

Response to RAI 5.4.2-1
a. The values of RT_{PTS} for all three Oconee units have been recalculated using the most recent surveillance data reported in BAW-2325, "Response to Request for Additional Information (RAI) Regarding Reactor Pressure Vessel Integrity," Revision 1, dated January 1999. The updated tables follow and will replace Tables 5.4-1, 5.4-2, and 5.4-3, in Exhibit A of the Application.

b. The surveillance data used to calculate the chemistry factors in the revised RT_{PTS} values reported in the Oconee response to RAI 5.4.2-1(a) are obtained from BAW-2325, Revision 1. The methodology used to apply the ratio procedure for the RT_{PTS} values reported in the attached tables is consistent with the methodology reported in BAW-2325, Revision 1.

Revised Table 5.4-1 —
Evaluation of Reactor Vessel Pressurized Thermal Shock Toughness Properties at 48 EFPY - Oconee Unit 1

Material Description				Chemical Composition								
Reactor Vessel Beltline Region Location	Mat'l. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}	Chemistry Factor	Fluence, n/cm² Inside Surface	ΔRT_{NDT}, F at 48 EFPY	Margin	RT_{PTS}, F at 48 EFPY	Screening Criteria
10 CFR 50.61 (Tables)												
Lower Nozzle Belt Forging	AHR 54	ZV-2861	A 508 Cl. 2	0.16	0.65	+3	119.3	1.11E+18	52.2	70.7	126.0	270
Intermediate Shell Plate	C2197-2	C2197-2	SA-302 Gr. BM*	0.15	0.50	+1	104.5	1.18E+19	109.3	63.6	174.0	270
Upper Shell Plate	C3265-1	C3265-1	SA-302 Gr. BM*	0.10	0.50	+1	65.0	1.31E+19	69.9	63.6	134.5	270
Upper Shell Plate	C3278-1	C3278-1	SA-302 Gr. BM*	0.12	0.60	+1	83.0	1.31E+19	89.2	63.6	153.9	270
Lower Shell Plate	C2800-1	C2800-1	SA-302 Gr. BM*	0.11	0.63	+1	74.5	1.31E+19	80.0	63.6	144.7	270
Lower Shell Plate	C2800-2	C2800-2	SA-302 Gr. BM*	0.11	0.63	+1	74.5	1.31E+19	80.0	63.6	144.7	270
LNB to IS Circ. Weld (100%)	SA-1135	61782	ASA/Linde 80	0.23	0.52	-5	157.4	1.11E+18	69.0	68.5	132.4	300
IS Longit. Weld (Both 100%)	SA-1073	1P0962	ASA/Linde 80	0.21	0.64	-5	170.6	9.24E+18	166.8	68.5	[230.3]	270
IS to US Circ. Weld (ID 61%)	SA-1229	71249	ASA/Linde 80	0.23	0.59	+10	167.6	1.19E+19	175.7	56.0	241.7	300
US Longit. Weld (Both 100%)	SA-1493	8T1762	ASA/Linde 80	0.19	0.57	-5	152.4	1.12E+19	157.3	68.5	220.8	270
US to LS Circ. Weld (100%)	SA-1585	72445	ASA/Linde 80	0.22	0.54	-5	158.0	1.27E+19	168.5	68.5	232.0	300
LS Longit. Weld (100%)	SA-1426	8T1762	ASA/Linde 80	0.19	0.57	-5	152.4	1.08E+19	155.8	68.5	219.3	270
LS Longit. Weld (100%)	SA-1430	8T1762	ASA/Linde 80	0.19	0.57	-5	152.4	1.08E+19	155.8	68.5	219.3	270
10 CFR 50.61 (Surveillance Data)												
LNB to IS Circ. Weld (100%)	SA-1135	61782	ASA/Linde 80	0.23	0.52	-5	141.1	1.11E+18	61.8	48.3	105.1	300
US to LS Circ. Weld (100%)	SA-1585	72445	ASA/Linde 80	0.22	0.54	-5	145.2	1.27E+19	155.8	48.3	199.1	300

* - SA-302 Grade B modified by ASME Code Case 1339

[ ]- Controlling value of RT_{PTS} reference temperature

Revised Table 5.4-2 —
Evaluation of Reactor Vessel Pressurized Thermal Shock Toughness Properties at 48 EFPY - Oconee Unit 2

Material Description				Chemical Composition								
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}	Chemistry Factor	Fluence, n/cm^2 Inside Surface	ΔRT_{NDT}, F at 48 EFPY	Margin	RT_{PTS}, F at 48 EFPY	Screening Criteria
10 CFR 50.61 (Tables)												
Lower Nozzle Belt Forging	AMX 77	123T382	A 508 Cl. 2	0.13	0.76	+3	95.0	1.19E+19	99.6	70.7	173.3	270
Upper Shell Forging	AAW 163	3P2359	A 508 Cl. 2	0.04	0.75	+20	26.0	1.28E+19	27.8	27.8	75.6	270
Lower Shell Forging	AWG 164	4P1885	A 508 Cl. 2	0.02	0.80	+20	20.0	1.27E+19	21.3	21.3	62.7	270
LNB to US Circ. Weld (100%)	WF-154	406L44	ASA/Linde 80	0.27	0.59	-5	182.6	1.19E+19	191.5	68.5	255.0	300
US to LS Circ. Weld (100%)	WF-25	299L44	ASA/Linde 80	0.34	0.68	-5	220.6	1.23E+19	233.3	68.5	[296.8]	300
10 CFR 50.61 (Surveillance Data)												
None												

[ ]- Controlling value of RT_{PTS} reference temperature

Revised Table 5.4-3 —
Evaluation of Reactor Vessel Pressurized Thermal Shock Toughness Properties at 48 EFPY - Oconee Unit 3

Material Description				Chemical Composition								
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}	Chemistry Factor	Fluence, n/cm² Inside Surface	ΔRT_{NDT}, F at 48 EFPY	Margin	RT_{PTS}, F at 48 EFPY	Screening Criteria
10 CFR 50.61 (Tables)												
Lower Nozzle Belt Forging	4680	4680	A 508 Cl. 2	0.13	0.91	+3	96.0	1.14E+19	99.5	70.7	173.2	270
Upper Shell Forging	AWS 192	522314	A 508 Cl. 2	0.01	0.73	+40	20.0	1.26E+19	21.3	21.3	82.6	270
Lower Shell Forging	ANK 191	522194	A 508 Cl. 2	0.02	0.76	+40	20.0	1.26E+19	21.3	21.3	82.6	270
LNB to US Circ. Weld (100%)	WF-200	821T44	ASA/Linde 80	0.24	0.63	-5	178.0	1.14E+19	184.6	68.5	248.1	300
US to LS Circ. Weld (ID 75%)	WF-67	72442	ASA/Linde 80	0.26	0.60	-5	180.0	1.22E+19	190.0	68.5	[253.5]	300
10 CFR 50.61 (Surveillance Data)												
Upper Shell Forging	AWS 192	522314	A 508 Cl. 2	0.01	0.73	+40	36.0	1.26E+19	38.3	34.0	75.5	270
Lower Shell Forging	ANK 191	522194	A 508 Cl. 2	0.02	0.76	+40	17.4	1.26E+19	18.5	17.0	112.3	270
LNB to US Circ. Weld (100%)	WF-200	821T44	ASA/Linde 80	0.24	0.63	-5	158.3	1.14E+19	159.5	48.3	202.8	300

[ ]- Controlling value of RT_{PTS} reference temperature

RAIs G-2 and G-4 are similar and the responses to both are provided following G-4.

RAI G-2 (11/18/98D)
Sections 4.3.2, 4.3.3, and 4.3.8 all describe new one time inspection programs to verify the presence or absence of various degradation mechanisms specific to certain components. These sections all deal with time dependent mechanisms. However, given that Oconee has been operating for approximately 24 years, discuss the rationale for delaying these inspections to the time period between the issuance of a license extension and the expiration of the existing license. The staff recognizes the financial constraints in the utility business, however, given some of the mechanisms specified, it is not clear why some programs are not advanced in schedule. What is the rationale for the schedule of the programs? Is there a plan for schedule or priority ranking among these various inspection programs? What is the rationale for this ranking?

RAI G-4 (12/3/98A)
Sections 4.3.4, 4.3.5, and 4.3.13 all describe new one-time inspection programs to verify the presence or absence of various aging effects specific to certain components. These sections all deal with time dependent effects. However, given that Oconee has been operating for approximately 24 years, discuss the basis for deferring performance of these inspections to the time period between the issuance of a license extension and the expiration of the existing license. Given some of the effects specified, it is not clear why some programs are not advanced in schedule. Discuss the rationale for the schedule and prioritization of the completion of these one-time inspection "programs". Provide the rationale for the prioritization.

Response to RAIs G-2 and G-4
The RAIs G-2 and G-4 are similar. For convenience, they are being answered together.

Section 4.3 of Exhibit A of the Application describes all of the new programs and activities that Duke has identified as required to manage the effects of aging for the period of extended operation. Within this section, there are three distinct groups of new programs and activities. The following is a discussion of the rationale for the proposed timing of these three groups of new programs and activities that are described in Section 4.3.

The first group of new programs and activities to manage the effects of aging can be considered to be those programs which have many activities that are required to be completed prior to conducting an inspection or examination prior to the end of the current operating license. These Group 1 programs and activities include the *Alloy 600 Aging Management Program* (4.3.1) and the *Reactor Vessel Internals Aging Management Program* (4.3.11). Following issuance of renewed licenses for Oconee, these programs and activities

will continue to develop the necessary methodologies such that the inspections can be performed prior to the end of the current operating license term for Oconee Unit 1. Industry operating experience, inspection results and NRC generic communications will be used to guide when the actual inspections will be performed at Oconee.

The second group of new programs and activities can be considered to be those that currently exist but do not have sufficient documentation available to demonstrate that they will be effective to manage the effects of aging during the period of extended operation. These Group 2 programs and activities are ongoing maintenance activities wherein the more rigorous record keeping requirements have not been in place and include *Keowee Oil Sampling Program* (4.3.5) and *Preventive Maintenance Activities* (4.3.8). The documentation aspect of these programs and activities is being enhanced. In the Application, Duke proposed that a self-assessment be performed prior to the end of the current license term to provide reasonable assurance that these programs and activities are effective at managing aging prior to beginning the period of extended operation.

The third group of new programs and activities are those where the examination or inspection will be performed after the renewed licenses are issued and prior to the end of the current operating license term. These Group 3 programs and activities include:

- *Cast Iron Selective Leaching Inspection* (4.3.2)
- *Galvanic Susceptibility Inspection* (4.3.3)
- *Keowee Air and Gas Systems Inspection* (4.3.4)
- *Once Through Steam Generator Upper Lateral Support Inspection* (4.3.6)
- *Pressurizer Examinations* (4.3.7)
- *Reactor Building Spray System Inspection* (4.3.9)
- *Reactor Coolant Pump Motor Oil Collection System Inspection* (4.3.10)
- *Small Bore Piping Inspection* (4.3.12)
- *Treated Water Systems Stainless Steel Inspection* (4.3.13)

The timing of when to perform new inspections and examinations listed in Group 3 is of particular interest in RAIs G-2 and G-4. Timing of new inspections was initially discussed with the staff in1997. By letter dated May 19, 1997, Duke submitted an example of the level of detail proposed for a license renewal application to describe a new inspection program. The staff reviewed this example and provided written feedback by letter dated August 13, 1997 (Reference 4.2-3 of Section 4.2 of the Application). Within this letter, staff technical comment #2 indicated that for the example provided, the examination should be provided during the last two periods of the fourth interval. Duke understood this staff comment to mean that all new inspections and examinations required for license renewal

should be performed toward the end of the initial 40-year operating license rather than earlier.

Duke proposed in the Application that each of the above Group 3 inspections would be performed following "issuance of the renewed operating licenses for Oconee Nuclear Station, and prior to February 6, 2013 (the end of the initial license of Oconee Unit 1)." New inspections will be conducted to characterize aging effects (if any) and to determine whether additional actions are required to manage them. In general, delaying these inspections provides further time for any aging effect to manifest itself, so that an appropriate aging management program can be implemented prior to the beginning of the period of extended operation. Absent any industry experience or NRC generic communication to perform the inspection earlier, the committed inspection will be performed during the latter part of the current operating license.

The following additional information specific to the new programs and activities listed in RAIs G-2 and G-4 is provided:

Section 4.3.2, Cast Iron Selective Leaching Inspection
Please see also our response to RAI 4.3.2-1. This activity will characterize loss of mechanical properties in cast iron due to selective leaching or graphitic corrosion. This type of corrosion attacks the pearlitic matrix of gray cast iron, leaving a weakened structure of graphite flakes and corrosion products. This is a very slow form of corrosion observed only in gray cast iron. Several pump casings at Oconee and Keowee are made of gray cast iron. Therefore, Duke will perform this inspection in order to characterize this aging effect. Searches of the operating experience database have shown no evidence of a generic problem with the selective leaching of gray cast iron.

Section 4.3.3, Galvanic Susceptibility Inspection
This activity will assess degradation of carbon steel and cast iron piping in raw water systems due to galvanic coupling with more cathodic metals such as stainless steel or copper alloys. Searches of past operating experience have shown that galvanic corrosion has historically not been a source of degradation of the raw water systems at Oconee. Since previous incidences of galvanic attack have been low, probabilities of future attack are expected to remain low.

Section 4.3.4, Keowee Air and Gas Systems Inspection
This activity will characterize loss of material due to general corrosion of the carbon steel components in the applicable systems. A historical lack of problems supports this conclusion. Periodic operation of the Keowee units for the purpose of surveillance and routine operation for the purpose of production generation also shows that the air and gas system components maintain functional capability. This inspection will further assure that no undetected degradation was occurring.

Section 4.3.5, Keowee Oil Sampling Program
This program precludes loss of material and pitting degradation by corrosion by managing the presence of water in Keowee lubrication systems. This program is a relatively new, but existing routine surveillance program. The oil sampling program began informally as routine good practices of the hydro-electric station operators. Inspection data has been retained since about 1990. The current program began in August 1997, and is managed via work orders and maintenance procedures. This program will be monitored for effectiveness via ongoing maintenance assessment activities at Oconee and enhancements will be made as determined by the assessments.

The "Timing of New Program or Activity" statement provided on page 4.3.13 of Exhibit A of the Application will be revised to read:

> Timing of New Program or Activity – The *Keowee Oil Sampling Program* is an existing program that will be continued into the extended period of extended operation. This program will be monitored for effectiveness via ongoing maintenance assessment activities at Oconee and enhancements will be made as determined by the assessments prior to February 6, 2013 (the end of the initial license term for Oconee Unit 1).

Section 4.3.8, Preventive Maintenance Activity Assessment
Please see our responses to RAIs 4.3.8-1 through 4.3.8-6. The preventive maintenance activities currently exist. The purpose of the Preventive Maintenance Activity Assessment is to determine the effectiveness of these existing plant maintenance activities. The assessment is applicable to a specific list of equipment and aging mechanisms identified within the program.

Section 4.3.13, Treated Water Systems Stainless Steel Inspection
Please see also our responses to RAIs 4.3.13-1 through 4.3.13-4. This activity will assess the condition of the applicable stainless steel systems due aging degradation mechanisms such as pitting and stress corrosion cracking. The condition of these systems is believed to be satisfactory due to the excellent quality of the water contained in them. Historically, no evidence exists at Oconee or in the industry that these aging effects are applicable to these systems. The probability for degradation of stainless steel by the treated or demineralized water in these systems is considered low.

RAI G-6 (12/3/98A)
Discuss how the inspections for small bore piping and pressurizer detect aging effects before there is a loss of the component intended functions? In your response, discuss how the scope of the inspections, the specific methods used, and basis for determining the frequency for the inspections supports your conclusions.

Response to RAI G-6
Small Bore Piping
The *Small Bore Piping Inspection* is driven by the consequences of small bore piping failures rather than a lack of confidence in the current inservice inspection techniques to manage aging. Operating experience suggests that cracking of small bore piping results in leakage that is detected prior to catastrophic failure of the pipe. As discussed in Section 3.4.3 of Exhibit A of the Application, cracking at welded joints is an applicable aging effect for small bore piping. Operating experience indicates that cracking of small bore piping that originates from the inner diameter of the pipe may occur by growth of fabrication flaws under normal service loads or by initiation and growth of service-induced flaws caused by one or more aging mechanisms (e.g., thermal fatigue). At present, the majority of Reactor Coolant System small bore piping failures (BAW-2243A, Section 3.4.1) have been attributed to thermal fatigue and/or high cycle fatigue. Cracking by high cycle fatigue is observed early in the lifetime of a component and is not an applicable aging effect. Cracking of small bore piping by thermal fatigue may be a concern during the period of extended operation since the damage is cumulative and a large population of small bore piping of NPS 1-inch and less were exempt from fatigue analyses through ASME Section III and USAS B31.7 Class I design rules. Therefore, cracking of small bore piping by thermal fatigue is an applicable aging effect for small bore piping.

The Oconee *Program to Inspect High Pressure Injection Connections to the Reactor Coolant System* focuses volumetric inspections at the locations where thermal fatigue of small bore piping (2 ½-inch NPS) is expected to occur. This program, which is driven by IE Bulletin 88-08 and Generic Letter 85-20, is an ongoing program and is described in Section 4.22 of Exhibit A of the Application. In addition, the proposed one-time inspection of a sample population of small bore piping at or near the end of the current term of operation will provide assurance that cracking by thermal fatigue is not occurring in the remaining population of small bore piping that does not receive volumetric inspections in accordance with ASME Section XI.

As described in Section 4.3.12 of Exhibit A of the Application, risk-informed methods will be used to select a population of small bore piping welded joints for a one-time inspection. The inspection method will include either destructive testing or a non-destructive examination that permits inspection of the inside surface of the piping.

Any indication of cracking identified during the *Small Bore Piping Inspection* or the *Program to Inspect High Pressure Injection Connections to the Reactor Coolant System* will initiate the Problem Investigation Process (PIP). The PIP is a process governed by a nuclear generation department directive that will initiate an engineering evaluation of the identified condition. The PIP evaluation is designed to consider the need to conduct a root cause analysis and determine corrective actions, which may include actions to prevent recurrence. For this example, the PIP evaluation will determine the need for a root cause analysis, including the establishment of methods to determine the extent of cracking. The evaluation will also determine corrective actions that assure a degraded component condition has not or will not exceed the limit required for qualifying the component for further service.

The combination of the ongoing *Program to Inspect High Pressure Injection Connections to the Reactor Coolant System* and the one-time inspection of a sample population of small bore piping welds will provide assurance that the small bore piping intended functions will be maintained consistent with the current licensing basis in the period of extended operation.

Pressurizer

As discussed in the Duke response to RAI 4.3.7-1, Duke does not consider pressurizer clad cracking to be an applicable aging effect for the period of extended operation. However, the one-time inspection of the pressurizer cladding at one Oconee unit at or near the end of the current operation will be performed to verify that cracking of cladding is not an applicable aging effect. With regard to cracking of the internal spray line and spray head, the ability to control Reactor Coolant System pressure would not be impaired if the internal spray line piping or spray head were cracked. Therefore, the one-time inspection of the spray line and spray head at or near the end of the period of extended operation is not required to ensure that the pressure control function is maintained consistent with the current licensing basis; however, it is good engineering practice to perform a visual inspection of the internal spray line piping and spray head if the vessel must be opened to inspect the cladding.

RAI G-7 (12/3/98A)
Please explain whether the inspections for small bore piping, and pressurizer provide for sample expansion or require follow up inspections if unacceptable indications are found. If not, please justify.

Response to RAI G-7
The purpose of the *Small Bore Piping Inspection* will be to validate that service-induced weld cracking is not occurring in the small bore Reactor Coolant System piping that does not receive a volumetric examination under ASME Section XI. The purpose of the *Pressurizer Examinations* will be to assess the condition of the pressurizer cladding, internal spray line, spray head, and heater bundle penetration welds. These inspections do not include provisions for sample expansion or follow-up inspections.

Any indication of loss of material or cracking identified during these examinations will initiate the Problem Investigation Process (PIP). The PIP is a process governed by a nuclear generation department directive that will initiate an engineering evaluation of the identified condition. The PIP evaluation is designed to consider the need to conduct a root cause analysis and determine corrective actions, which may include actions to prevent recurrence. For this example, the PIP evaluation will determine the need for a root cause analysis, including the establishment of methods to determine the extent of cracking or the amount of material lost. The evaluation will also determine corrective actions that assure a degraded component condition has not or will not exceed the limit required for qualifying the component for further service.

RAI G-8 (12/3/98A)
Please discuss the confirmation process in the inspections for alloy 600, small bore piping, and pressurizer, i.e., when corrective actions are completed, the follow up activities performed to confirm that the corrective actions are completed, root cause determination performed, and recurrence prevented. (The discussion of this element in the QA program was not clear, stating that it applied to "more significant events.")

Response to RAI G-8
Any indications identified during the *Alloy 600 Aging Management Program Inspections*, the *Small Bore Piping Inspection* or the *Pressurizer Examinations* will be evaluated using the Problem Investigation Process (PIP). The PIP is a process governed by a nuclear generation department directive that will initiate an engineering evaluation of the identified condition. The PIP evaluation is designed to consider the need to conduct a root cause analysis and determine corrective actions, including confirmation process, which may include actions to prevent recurrence. For conditions warranting such action, PIP confirms

the identified condition has been addressed. The evaluation will also determine corrective actions that assure a degraded component condition has not or will not exceed the limit required for qualifying the component for further service

RAI G-9 (12/3/98A)
For the Inspections for alloy 600, small bore piping, and pressurizer, discuss Oconee or applicable industry operating experience from similar programs or inspection techniques used to develop this inspection program.

Response to RAI G-9
The Oconee *Alloy 600 Aging Management Program* inspections for the top susceptible Alloy 600 locations will predominately make use of industry accepted and approved NDE techniques. For other applications requiring specialty tools, first-of-a-kind NDE techniques may be developed which would require a process demonstration similar to that performed for the CRDM inspections discussed in Section 4.10 of Exhibit A of the Application.

See the response to RAI 4.3.7-1 for a discussion of industry experience related to pressurizer cladding inspections.

Very little industry experience is available for the *Small Bore Piping Inspection Program.* Piping two inches and smaller is generally not conducive to volumetric examination because of the geometry of the piping. For piping selected for inspection in this size range, a destructive examination will most likely be performed. Piping will be removed from service, cut open, and examined visually for signs of cracking. Indications of cracking detected visually in the sample can be examined more thoroughly by routine NDE such as dye penetrant testing or more advanced failure analysis techniques such as Scanning Electron Microscopy (SEM) or Energy-Dispersive Spectroscopy (EDS) in a metallurgical laboratory.

ATTACHMENT 2

Oconee Nuclear Station

Application for Renewed Operating Licenses

Responses to NRC Requests for Additional Information (RAI)

Set # 04
February 17, 1999

RAI 2.2-1 (11/30/98B)
Section 54.4(a)(3) requires that all plant systems, structures, and components relied on in safety analyses or plant evaluations to demonstrate compliance with Commission's regulations for fire protection (10 CFR 50.48) be included within the scope of license renewal. Section 2.2.2.1, "Fire Protection," of the license renewal application identifies that the applicant reviewed a number of NRC safety evaluation reports to determine the Oconee structures and mechanical systems relied upon to meet the requirements of Appendix R to 10 CFR Part 50. Section 2.2.2.1 of the license renewal application also states that the applicant identified the structures and mechanical systems required to demonstrate compliance with BTP 9.5-1 and Appendix R by reviewing the Oconee-specific documents addressing each topic and that a structure or mechanical system is within the scope of license renewal when a portion is relied upon for compliance with the NRC fire protection regulations. The applicant did not explicitly address whether or not it included all plant systems, structures, and components relied on to demonstrate compliance with 10 CFR 50.48 within the scope of license renewal for Oconee. The application also appears to be limited in scope in that it refers only to "structures and mechanical systems." Please provide the following information:

a. Verify that all plant systems, structures, and components relied on in safety analyses or plant evaluations to demonstrate compliance with 10 CFR 50.48 were included within the scope of license renewal for Oconee. (So that the staff can make an appropriate finding in its safety evaluation, please frame the response in the context of 10 CFR 50.48.)

b. Identify the specific types of licensee-controlled safety analyses, plant evaluations, and documentation (e.g., UFSAR, fire hazards analysis, safe shutdown analysis, etc.) that were used to identify the plant systems, structures, and components that were included within the scope of license renewal for Oconee.

c. Describe how the documents identified in Section 2.2.2.1 of the license renewal application and the documents identified in response to Question 1.b, above, were used to determine the systems, structures, and components, which are credited for compliance with 10 CFR 50.48, are within the scope of license renewal per 10 CFR 54.4(a)(3).

Response to RAI 2.2-1
a. The requirements governing fire protection for all nuclear power plants are contained in §50.48, Fire Protection. Specifically, §50.48(b) prescribes the requirements that nuclear power plants licensed to operate prior to January 1, 1979, which includes Oconee Nuclear Station, comply to Branch Technical Position 9.5-1 and certain provisions of Appendix R. This regulation states that:

"Except for the requirements of sections III.G, III.J, and III.O, the provisions of appendix R to this part shall not be applicable to nuclear power plants licensed to operate prior to January 1, 1979, to the extent that fire protection features proposed or implemented by the licensee have been accepted by the NRC staff as satisfying the provisions of appendix A to Branch Technical Position BTP APCSB 9.5-1 reflected in staff fire protection safety evaluation reports..."

The Fire Protection Safety Evaluation Report for Oconee Nuclear Station was issued by the NRC on August 11, 1978. In addition, Facility Operating License Condition 3.E was issued and currently states:

> *"Duke Energy Corporation shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report for the facility and as approved in the SERs dated August 11, 1978, and April 28, 1983; October 5, 1978, and June 9, 1981 Supplements to the SER dated August 11, 1978; and Exemptions dated February 2, 1982; August 31, 1983; December 27, 1984; December 5, 1988; and August 21, 1989 subject to the following provision:*

The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire."

The Oconee Updated Final Safety Analysis Report, Section 9.5.1, *Fire Protection System,* contains a description of the complete fire protection program at Oconee.

In summary, Oconee meets the requirements of §50.48 by complying with Branch Technical Position 9.5-1 and the applicable portions of Appendix R. Oconee continues to implement the fire protection features that are described in the Oconee UFSAR Section 9.5.1, the NRC safety evaluation report, supplements to the SER, and exemptions as listed in License Condition 3.E and by meeting the requirements of Sections III.G, III.J, and III.O of Appendix R. Therefore, all of the structures, systems and components relied on in safety analyses and plant evaluations to meet these requirements are included within the scope of license renewal for Oconee Nuclear Station.

b. In addition to the three licensing documents listed in Section 2.2.2.1 of Exhibit A of the Application and the Oconee Updated Final Safety Analysis Report, additional plant documents were used to identify the fire protection and Appendix R systems, structures and components that are within the scope of license renewal for Oconee. These documents include engineering documents, such as Design Basis Documents, drawings, such as the

flow diagrams from which the Oconee License Renewal Flow Diagrams (OLRFDs) are based, and Oconee Engineering calculations and specifications. These documents provide fire protection and Appendix R licensing basis and design basis information for Oconee.

c. All components committed to in the licensing documents listed in Section 2.2.2.1 of Exhibit A of the Application are within the scope of license renewal. The licensing documents were reviewed in search of commitments made to meet the regulations. Any structures or components that are relied upon for meeting the commitments are included within the scope of license renewal. Additionally, plant documents mentioned above were reviewed to determine components that are relied upon for fire protection or Appendix R safe shutdown. For example, the Appendix R engineering specification provides a highlighted set of mechanical drawings that show the functional mechanical boundaries necessary for cold shutdown in the event of a fire in given fire locations. Also, Oconee flow diagrams are designated as a defined QA Condition if equipment on the drawing is related to fire protection. All of the relevant documents were reviewed and applicable components from the documents were included within the scope of license renewal.

Electrical components required to meet the Fire Protection regulation of §54.4(a)(3) are addressed as a super set. The response to RAI 2.6-1 provides additional information concerning electrical scoping.

RAI 2.2-2 (11/30/98B)
Verify that the fire protection scoping process has been updated since its inception and that changes to the fire protection program documentation identified in response to Question 1.b, above, have been reviewed and captured by the fire protection scoping process, as appropriate.

Response to RAI 2.2-2
The Fire protection Safety Evaluation Report for Oconee requires that the fire protection program be maintained for the facility. By incorporating fire protection and Appendix R requirements into plant documents, Oconee ensures that the program is updated as needed. Within the plant modification process, it is required that the documents associated with fire protection and Appendix R be reviewed to determine if the modification affects, or is affected by, any information within the documents. Plant documents listed in response to RAI 2.2-1b, such as Design Basis Documents, flow diagrams, calculations, and specifications, are living documents and are updated any time plant or licensing changes warrant revision. The Oconee Update Final Safety Analysis Report is updated annually. The Oconee license renewal fire protection scoping defined by §54.4(a)(3) and described in response to RAI 2.2-1 used these updated documents.

RAI 2.2-3 (11/30/98B)
Identify the fire protection components that have been determined to be within the scope of license renewal, per 10 CFR 54.4, but have been excluded from aging management review because they are subject to replacement based on qualified life or a specified time period as permitted under 10 CFR 54.21(a)(1)(ii).

Response to RAI 2.2-3
None of the fire protection components above has been excluded from aging management because they are subject to replacement based on qualified life or a specified time period as permitted under §54.21(a)(1)(ii). However, as discussed in responses to RAIs 2.2-4 and 2.2-5, several components have been excluded from aging management review pursuant to the guidance contained in the Statement of Considerations associated with the final Part 54 rule.

RAI 2.2-4 (11/30/98B)
Describe, in detail, how (a) the equipment and components relied upon for post-fire cold shutdown and (b) the fire detection system were addressed in the system level scoping process and the aging management review process.

Response to RAI 2.2-4
(a) Appendix R, Section III.G requires cold shutdown capability in the event of a fire in certain locations of the plant. Plant-level analyses have been performed and the results documented in the engineering documents described in response to RAI 2.2-1. These documents list the Appendix R, Section III.G systems and components required to place the plant in cold shutdown for various fire location scenarios. These documents were reviewed to determine the systems, structures, and components relied upon to meet the fire protection criteria of § 54.4(a)(3). All of the systems, structures, and components listed in these plant documents as required for Appendix R cold shutdown is within the scope of license renewal. The screening process described in Section 2.5.2 of Exhibit A of the Application was then performed on these components to determine the components subject to aging management review. Those components that were not screened out in accordance with § 54.21 are included in the aging management review in the applicable sections of the Application.

(b) The Fire Detection System is an electrical system. The electrical components within the system are scoped and screened as described in the Response to RAI 2.6-1. Briefly, the electrical portions of the plant, including the Fire Detection System, are divided into distinct electrical component groups or commodities. These electrical components are then screened and scoped to determine which components meet the criteria of §54.21(a)(1)(i), §54.4(a), and §54.21(a)(1)(ii). The electrical components included in the aging management review, as determined by the screening and scoping, are:

- specific insulated cables and connections,
- specific high voltage insulators,
- high voltage enclosed, phase bus,
- specific switchyard bus, and
- specific transmission conductors.

Of these components, only insulated cables and connections are used in the Fire Detection System.

As discussed in Section 2.6.6.1.2 of Exhibit A of the Application and clarified in the Response to RAI 2.6-4, insulated cables and connections used for fire detectors (which are part of the Fire Detection System) are determined not to meet the criteria of §54.21(a)(1)(ii). All other insulated cables and connections in the Fire Detection System are included in the aging management review. Details of the aging management review for these insulated cables and connections are contained in Section 3.6.3 of Exhibit A of the Application.

RAI 2.2-6 (12/1/98B)

In OLRP-1001, Section 2.2, "Identification of Systems, Structures, and Components Within the Scope of License Renewal," the applicant identifies the methodology used to identify structures and *mechanical* systems at Oconee that are within the scope of license renewal. The methodology used to identify electrical components within the scope of license renewal and subject to aging management review is described in Section 2.6 of OLRP-1001.

In Subsection 2.2.1.1, "Mechanical Systems," the applicant states "Because Oconee was licensed before terms such as 'safety-related' were more precisely defined by the NRC, a list of the Oconee safety-related systems, structures, and components, *in and of itself*, will not meet the intent of 10 CFR 54.4(a)(1). Because the criteria in 10 CFR 54.4(a)(1) are the scoping criteria of many modern-day, regulatory-required programs, Oconee conducted a design study that validated all functions required for the successful mitigation of Oconee design basis events and identified the systems and components relied upon to complete those functions. The individual design basis event mitigation calculations produced as a result of

the study contain a list of the system functions required to successfully mitigate each event. Duke determined that the systems that perform these functions are within the scope of license renewal."

During a site visit to review the Oconee license renewal scoping and screening process, which was conducted by the NRC staff on October 27 through 30, 1998, at Duke Power Corporate offices in Charlotte, North Carolina, the staff learned that the "*design study*" identified in Subsection 2.2.1.1 and the Oconee Safety-Related Designation Clarification (OSRDC) project were one and the same.

Specifically, in its November 4, 1983, response to Generic Letter (GL) 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events" (July 1983), as supplemented by letters dated January 17, 1984, and June 9, 1987, Duke described the scope of the Oconee operational quality assurance (QA) program for safety-related equipment classification. The NRC staff approved the scope of the Oconee operational QA program via a safety evaluation dated November 4, 1987.

In a supplemental response to GL 83-28, dated April 12, 1995, Duke provided amplifying information on Oconee's QA-1 licensing basis, and on information provided to the NRC Region II staff during a February 6, 1995, meeting. In Attachment 3 to this letter, "Supplemental Response to Subpart 1 of Section 2.2.1 of GL 83-28 General Criteria for Classifying QA-1 SSCs [structures, systems, and components]," Duke stated that the list of additional QA-1 SSCs would be developed through the OSRDC project by July 10, 1995. Also, in Attachment 4, "Oconee Licensing Position on Non QA-1 SSCs which are used to Mitigate Accidents," Duke committed to developing a new QA classification (QA-5) such that these SSCs can be identified "for testing and maintenance under selected Appendix B [to 10 CFR Part 50] criteria without procuring the SSCs per Appendix B." [OLRP-1001, Section 2.2]

Based on the above, the staff is requesting that Duke provide the following information:

a. Please clarify the extent to which the Oconee license renewal process described in OLRP-1001 relied upon the OSRDC results.

b. Please describe the specific process (and its current status) used by Duke to confirm that the OSRDC project has identified all Oconee structures, systems, and components (including electrical) that perform the functions identified in 10 CFR 54.4(a).

Please identify and describe the administrative controls (and associated commitments) currently in place at Oconee to ensure that QA-5 structures, systems and components

(identified through the OSRDC project), and subject to aging management review, will be adequately managed during the life of the renewed license. If such controls are not in place, please provide justification.

Response to RAI 2.2-6
As background to the staff's specific requests for information on this topic, additional description is provided regarding the design study referenced in Exhibit A of the Application. The design study refers to one initiative of the Oconee Safety-Related Clarification (OSRDC) project. The first initiative of the project was to clarify Oconee's QA-1 licensing basis by developing a list of all QA-1 systems, structures, and components at Oconee. This activity was a committed NRC activity in response to GL 83-28. The list was submitted to NRC in letters dated July 10, 1995, and May 6, 1996. Submittal of these letters constitutes the completion of this NRC commitment by Duke Energy. No other portions or activities of the OSRDC project were committed to the staff at that time or any time hence.

The second initiative of the OSRDC project was to clarify Oconee's licensing basis with respect to design basis event mitigation requirements. This initiative of the project is an internal Duke activity that does not represent a commitment to the NRC. This activity has been completed.

The third initiative involves identifying important non-safety related systems and components, and the fourth initiative is to implement an augmented QA program for those systems and components. This program is to be named "QA-5". These initiatives are targeted for completion in 2000.

Scoping of mechanical systems and components relied upon the results of the second initiative of the OSRDC project. Oconee engineering calculations were performed for this portion of the project and resulted in the identification of those systems and components relied upon to mitigate the consequences of design basis events. The results of these calculations were therefore used to meet the criteria of § 54.4(a)(1)(i), (ii), and (iii) for mechanical systems and components. The results of the Oconee engineering calculations were also used as input to identify portions of those mechanical systems and components required to meet the criteria of § 54.4(a)(2). Sections 2.2.1.1(a) and 2.2.1.1(b) of Exhibit A of the Application describe how these results were used for mechanical system scoping.

As clarification, the results of the Oconee engineering calculations performed as part of the OSRDC project were used to identify those mechanical systems and components required to meet only § 54.4(a)(1) and a portion of § 54.4(a)(2). The calculations performed for the OSRDC project and used as input for license renewal scoping are QA-1 calculations performed in accordance with the Duke Energy Corporation Quality Assurance Program

with guidance provided by Duke Power Engineering Directives. The Quality Assurance Program assures that Duke Energy Corporation's nuclear power plants are designed, constructed, tested, and operated in conformance with good engineering practices and to the criteria established in Appendix B of 10CFR 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants", and to approved industry standards, such as ANSI N45.2-1971 and ANSI N18.7-1976. The Duke Energy Corporation Quality Assurance Program provides for the independent assurance of activities associated with items and tasks critical to the safety and integrity of the station. When such a task is being performed, Duke Power Engineering Directives provide guidance for these activities, such as requiring independent verification and approval for the completion of a QA-1 calculation. By complying with these established governing standards, Duke has confidence that its process for performing QA-1 analyses, such as those used to identify mechanical systems and components that perform the functions identified in § 54.4, assures accuracy and completeness.

Structural and electrical scoping was performed differently than mechanical. Section 2.2.1.2 of Exhibit A of the Application provides a discussion of the methodology for scoping structures and Section 2.7.1 for structural components. A complete scoping discussion for electrical components is given in response to RAI 2.6-1.

The third and fourth initiatives of the OSRDC project, the identification and implementation of an augmented QA program ("QA-5") for important non-safety related systems and components, are beyond the scope of license renewal as defined by §54.4. These initiatives will develop an augmented quality program for components outside the established QA-1 program. Criteria in addition to the criteria of §54.4 and §54.21 will be used to establish the set of components within the scope of the QA-5 program. For example, the QA-5 program will focus almost entirely on components that perform active functions. Thus, the QA-5 scope will not be equal to the scope of non-safety related components within the scope of license renewal. The future QA-5 components within the scope of license renewal will be treated as non-safety related components within scope. The response to RAI G-1 provides the discussion of the administrative controls of non-safety related components within the scope of license renewal.

Mechanical scoping and screening was discussed during the staff's site visit on October 27, 1998. At that time, a detailed description of OSRDC was provided by Duke. Based on the staff's trip report dated February 8, 1999, it is believed that Duke may not have fully explained that license renewal scoping is independent from the implementation of a QA-5 program at Oconee. In most instances in the trip report where "QA-5 components" are discussed, "non-safety related components within the scope of license renewal" would more accurately define the components. In addition to providing information requested by this

RAI, this response is intended to clarify the misconception concerning QA-5 by explaining that QA-5 components will not equal the non-safety related components within the scope of license renewal.

RAI 2.2-8 (12/2/98E)
Spent fuel pool (SFP) area ventilation and SFP coolant makeup are often credited in maintaining stored fuel temperature within prescribed limits during loss of spent fuel pool cooling events. Portions of the heating, ventilation and air conditioning systems that provide for SFP area ventilation are not identified as being within the scope of license renewal in the Oconee integrated plant assessment. Provide a basis for this determination or include SFP area ventilation within the scope of license renewal and, therefore, subject to an aging management review. Alternatively, identify where in the application these functions are addressed, if they are addressed elsewhere.

Response to RAI 2.2-8
The SFP ventilation is in operation during normal operation of the respective units. Plant analyses show that the system is not required to remain functional during or following any design basis event to ensure any of the functions required by § 54.4(a)(1)(i) through (iii). The system also does not meet the criteria of § 54.4(a)(2) or (3). Because the system does not meet any of the scoping criteria set forth in § 54.4, it is not within the scope of license renewal.

RAI 2.5.3-1 (12/1/98A)
Flow Diagrams OLRFD-116E-1.1, 2.1 and 3.1 do not include the piping and ductwork that supply air to the steam generator cavity and reactor vessel annulus and direct condensate to the reactor building sump. Discuss if this ductwork or piping is credited in any safety analyses. At a minimum, please, address the following analyses or assumptions: (1) initial or normal operating temperature assumed in the steam generator cavity and reactor vessel annulus for the purpose of equipment qualification, (2) normal operating temperature assumed to support the integrated exposure before a 10% reduction in sensitivity for the out-of-core neutron detectors as given by Table 7-4 of the Oconee Final Safety Analysis Report (FSAR), and (3) reactor building sump inventory. Considering the above discussion, clarify if this piping and ductwork is included within the scope of license renewal and subject to aging management review. If not, provide the basis for their exclusion.

Response to RAI 2.5.3-1
The ductwork that supplies air to the steam generator cavity and reactor vessel annulus and the piping that directs condensate to the reactor building sump are not within the scope of license renewal because they are not credited with supporting any system function as defined in § 54.4 (a)(1), (2), (3) or (b). In particular, the ductwork is not relied upon for maintaining temperatures in the area in accordance with equipment qualification requirements.

(1) Temperature measurements in the steam generator and reactor vessel cavities are recorded and trended on an ongoing basis. Adverse changes are addressed on an ongoing basis, also. If temperatures rise substantially above normal operating ranges for a period of time, that period of time at high temperatures would be evaluated for impact on the established average ambient temperatures used in the qualified life calculations of equipment located in the cavities. It should be noted that conservatisms are incorporated into the establishment of the average ambient temperatures for a given area. In addition, the qualified life is typically rounded down, e.g., 10.8 years to 10 years, to account for infrequent operational occurrences such as fan failure and fouled coolers which could result in increased ambient temperatures. Since the qualified life is based on a "time at temperature" relationship, an increase in ambient temperature does not automatically put a piece of equipment at the end of its qualified life.

(2) The out-of-core neutron detectors are part of the Nuclear Instrumentation System. The 10% reduction in sensitivity for the out-of-core neutron detectors as given by Table 7-4 of the Oconee Updated Final Safety Analysis Report, is primarily a function of neutron flux intensity and not temperature. Therefore, the ambient temperature is not a significant factor in sensitivity degradation of the detector. Calibration of the Nuclear Instrumentation system would detect any change in sensitivity and/or inability to meet performance requirements and the detector would be replaced per established procedures.

(3) Finally, reactor building sump inventory analyses do not rely on the water supplied by the Reactor Building Cooling System condensate drain to the reactor building normal sump.

RAI 2.5.3-2 (12/1/98A)
Section 9.4.6.2 of the Oconee FSAR states that the fusible links holding the dropout plates provided in the ductwork below the coils melt and drop off, assuring that a positive path for recirculation of the Reactor Building atmosphere is available. Discuss how fusible dropout registers and links can be classified as non-nuclear safety related when they are credited in the post accident containment heat removal safety analysis. Based on the above, clarify if the fusible links are considered within the scope of and subject to aging management review. If not, provide the basis for their exclusion.

Response to RAI 2.5.3-2
The fusible links are considered within the scope of license renewal. They are not subject to an aging management review, in accordance with § 54.21, because they change state (melt) to perform their intended function.

The safety classification of the fusible dropout registers and links is an issue that is not associated with the license renewal process defined by 10 CFR Part 54.

RAI 2.5.3-3 (12/1/98A)
Figure 6.2, "Flow Diagram of Reactor Building Spray System," of the Oconee FSAR shows valve LP-16 being supplied by Decay Heat Removal Pump A. This is not consistent with Flow Diagrams OLRFD-102A-1.2, 2.2 and 3.2 which show this valve being supplied by Decay Heat Removal Pump B. Please clarify this inconsistency.

Response to RAI 2.5.3-3
The piping containing LP-16 is supplied by Decay Heat Removal Pump A, as shown on the Oconee License Renewal Flow Diagrams, OLRFD-102A-1.2, 2.2, 3.2. The Oconee Updated Final Safety Analysis Report (UFSAR) figure is incorrect. The figure has been corrected and placed in the UFSAR Annual Update process to be incorporated in the 1998 UFSAR annual update to be submitted to the staff in June 1999.

RAI 2.5.3-4 (12/1/98A)
Figure 6.2, "Flow Diagram of Reactor Building Spray System," of the Oconee FSAR shows two valves that isolate the reactor building spray pumps from the spray headers, 1(ES) and 2(ES). This is not consistent with Flow Diagrams OLRFD-102A-1.2, 2.2 and 3.2 which show the valves as ES-7 and ES-8. Please clarify this inconsistency.

Response to RAI 2.5.3-4
The "ES" designation on equipment shown in the Oconee Updated Final Safety Analysis Report (UFSAR) Figure 6.2 and the Oconee License Renewal Flow Diagrams (OLRFDs) indicate that the equipment is actuated by an Engineered Safeguards (ES) channel. The valves in question are Reactor Building Spray System valves BS-1 and BS-2, as indicated by the note at the bottom of the UFSAR Figure 6.2 that states "All valves 'BS' except as noted." These valves can also be seen on OLRFD 103A-1.1, 2.1, and 3.1 at grid locations E8 and J8. The UFSAR figures do not state ES channel numbers associated with the equipment. For example, the Reactor Building Spray pumps are ES actuated and the UFSAR figure shows "(ES)" below the pumps. Likewise, the UFSAR Figure 6.2 shows that valves BS-1 and BS-2 are ES actuated by indicating "(ES)" below the "1" and "2" that label the valves. Unlike the UFSAR figures, the Oconee License Renewal Flow Diagrams indicate ES channel numbers. For example, "ES-7" and "ES-8" are denoted below the Reactor Building Spray pumps on OLRFD 103A-1.1, 2.1, and 3.1. The OLRFD also provides the valves' ES channel number by indicating "ES-7" and "ES-8" below the "BS-1" and "BS-2" that label the valves.

Set # 04
February 17, 1999

RAI 2.5.5-1 (11/30/98C)
Page 6-38, Section 6.3.2.5, UFSAR [updated December 31, 1997], indicates that all components with surfaces in contact with water containing boric acid are protected from corrosion and deterioration. With the exception of the borated water storage tank, the major components in low pressure injection are constructed of stainless steel. The borated water storage tank is made of carbon steel with an interior phenolic coating to protect it from corrosion and deterioration. Clarify if the coating is relied upon to ensure the intended function of the borated water storage tank for the period of extended operation. If it is, describe the program to maintain the coating. If not, provide the basis for its exclusion.

Response to RAI 2.5.5-1
The internal coating of the Borated Water Storage Tank (BWST) is a physical design feature of the tank. It cannot, therefore, be an aging management program. As described in Section 3.5.5.3.2 of Exhibit A of the Application, loss of material of the carbon steel was determined to be an applicable aging effect for the tank given a carbon steel and borated water material/environment combination. The aging effect is managed by the Borated Water Storage Tank Internal Coatings Inspection portion of the Preventive Maintenance Activities. Section 4.3.8 of the Application describes this activity and more detail of the program is provided in response to RAI 4.3-8. This activity will manage the effect of loss of material of the tank by inspecting the condition of the inside of the tank, including the coating. This component, material, aging effect, and aging management program combination can be seen in Table 3.5-3 of the Application.

RAI 2.5.5-2 (11/30/98C)
Boric acid solution is stored in heated and insulated tanks and is piped in heat-traced and insulated lines to preclude precipitation of the boric acid. Clarify if the insulation material is within the scope of license renewal. If so, provide a cross reference to where these items are discussed in the submittal. If not, provide the basis for their exclusion.

Response to RAI 2.5.5-2
The tanks within the scope of license renewal in the Emergency Core Cooling System include the Letdown Storage Tank, the Core Flood Tank, and the Borated Water Storage Tank. The Letdown Storage Tank stores Reactor Coolant System letdown and provides suction to the High Pressure Injection system, which is normally in service. Thus, temperatures are high enough that heating and insulation of the tank for boron precipitation concerns are not necessary. The Core Flood Tanks store borated water for accident purposes. These tanks are located in the Reactor Building such that temperatures are high enough that heating and insulation of the tank for boron precipitation concerns are not necessary.

The Borated Water Storage Tanks stores borated water for suction to emergency systems for accident conditions. These tanks are located in the yard and are heated and insulated for the purpose of precluding boron precipitation. Additionally, the associated piping that is located in the yard is heat traced and insulated for the same purpose. The heaters, heat tracing, and insulation are designed to maintain the Borated Water Storage Tank inventory above Technical Specifications temperature limits during normal operation. The heaters run only occasionally to serve this purpose. The insulation material on the tank and piping is not required to support any system function that is required during or following any design basis event to satisfy the criteria of §54.4(a)(1)(i), (ii), or (iii). It follows, then, that the insulation also does not meet the criteria of §54.4(a)(2). It is not required to meet any of the regulations of §54.4(a)(3). The insulation is therefore not within the scope of license renewal.

RAI 2.5.6-9 (12/2/98C)
The following components are not listed on Table 2.5-9, yet are identified as WSLR on the flow diagrams included in the parentheses:

1. HPSW Pump A Air Cooler (K6, 124C-1.1),

2. Flow restricting orifice (F10, 124C-1.1),

3. Annubar tube (E10, 124C-1.2),

4. Elevated storage tank (E1, 124C-1.4), and

5. Quick disconnects (e.g., C8, 124C-2.2).

Indicate whether these components are within the scope of license renewal or, if not, provide a justification for their exclusion

Response To RAI 2.5.6-9
1. HPSW Pump A and B Motor Air Coolers are within the scope of license renewal but are not subject to an aging management review, therefore not listed in Table 2.5-9. Duke considers the coolers to be a sub-component of the motor. Per § 54.21(a)(1)(i), motors are not subject to an aging management review.

2. Flow Restricting Orifices are within the scope of license renewal and subject to an aging management review and should have been listed in Table 2.5-9. A revision to the HPSW portion of Table 2.5-9 is provided in response to RAI 4.16-11.

3. Annubar Tubes are within the scope of license renewal and subject to an aging management review and should have been listed in Table 2.5-9. A revision to the HPSW portion of Table 2.5-9 is provided in response to RAI 4.16-11.

4. The Elevated Water storage Tank is considered to be a structure which is within the scope of license renewal and subject to aging management review. It is described in Section 2.7.10.3 of Exhibit A of the Application.

5. Quick Disconnects are within the scope of license renewal and are encompassed by the commodity group "PIPE" and are listed in Table 2.5-9 of Exhibit A of the Application. For Oconee License Renewal, commodity group "PIPE" includes but is not limited to, pipe, blind flanges, blank flanges, elbows, pipe fittings, thermowells, quick disconnects.

Set # 04
February 17, 1999

Please note that several clarifications to Table 2.5-9 of Exhibit A of the Application have been made in response to RAI 4.16-11. Please use the table provided in response to RAI 4.16-11 for the High Pressure Service Water System.

RAI 3.5.12-1 (12/3/98A)
Section 3.5.12 states that the applicable aging effects for this system are summarized in Table 3.5.1. It appears that Table 3.5-10 is meant. Please confirm.

Response to RAI 3.5.12-1
The statement in Section 3.5.12 of Exhibit A of the Application is incorrect. It should have stated that the applicable aging effects for the Reactor Coolant System Vents, Drains, and Instrument Lines are summarized in Table 3.5-10, not Table 3.5-1 of the Application.

RAI 3.5.14-5 (12/3/98A)
Industry experience has shown that uncoated carbon steel piping may experience loss of material due to corrosion. Are the underground piping and main fuel oil storage tank carbon steel? If so, are they protected by a combination of coatings and cathodic protection and are these credited as a means of aging management? If so, discuss the elements of the aging management program that would address preservation and maintenance of the coatings and cathodic protection to ensure that degradation of the carbon steel structures and components does not occur?

Response to RAI 3.5.14-5
Section 3.5.14 of Exhibit A of the Application performs the aging management review on only the internal environment of this system. It appears from the question that the external aging management review is of interest to the reviewer. Assuming this to be true, the following information is provided. The main fuel oil tank is carbon steel and associated piping is stainless steel. The tank is coated externally. Loss of material was identified in Section 3.5.2.7.4 of the Application as an applicable aging effect for the carbon steel tank in an underground environment. The aging management review for the external surfaces of this carbon steel tank, as well as components constructed of other materials in an underground environment, is located in Section 3.5.2.7.4 of the Application. From that section of the Application, it is stated that the *Preventive Maintenance Activities* is credited with managing loss of material of these components. The *Preventive Maintenance Activities* are discussed in Section 4.3.8 of the Application and in response to RAI 4.3.8-1.

RAI 3.5.14-6 (12/3/98A)
Fouling in the auxiliary service water system is mentioned. What plans, if any, are there to use biocides to manage the effects of/control fouling and if so what kinds of biocide will be used?

Response to RAI 3.5.14-6
The Auxiliary Service Water System takes suction directly from the Condenser Circulating Water System intake piping from Lake Keowee. Oconee has no plans to use biocides to manage the effects of fouling in this system. The portion of the auxiliary service water system exposed to raw water and subject to fouling is a limited portion of the system that includes the pump, the pump discharge piping up to the pump discharge isolation valve, and the minimum recirculation piping. The remainder of the piping in the system is drained and exposed to air, and is not subject to fouling. As stated in Table 3.5-4 of Exhibit A of the Application, fouling in the limited portion of the Auxiliary Service Water System that is subject to fouling will be managed by *System Performance Testing Activities*. *System Performance Testing Activities* are discussed in Section 4.27 of Exhibit A of the Application. The response to RAI 4.3.8-2 provides additional clarification concerning the aging effects and programmatic oversight for the Auxiliary Service Water System.

RAI 4.3.13-1 (12/3/98A)
How does the proposed one time inspection's scope, and methodology detect aging effects before there is a loss of the component intended functions?

Response to 4.3.13-1
The purpose of the *Treated Water Systems Stainless Steel Inspection* is to determine the applicability of loss of material and cracking of specific portions of those treated water systems addressed in Section 4.3.13 of Exhibit A of the Application. If no indications of loss of material or cracking are identified, the aging effect will be considered not applicable to these systems with this particular material/environment combination. Any indication of loss of material or cracking identified during the *Treated Water Systems Stainless Steel Inspection* will initiate the Problem Investigation Process (PIP). The PIP is governed by a nuclear generation department directive that will initiate an engineering evaluation of the identified condition. The PIP evaluation is designed to consider the need to conduct a root cause analysis and determine corrective actions, which may include actions to prevent recurrence. For this example, the PIP evaluation will determine the need for a root cause analysis, including the establishment of methods to determine the amount of material lost. The piping evaluation will also determine corrective actions that assure a degraded component condition has not or will not exceed the limit required for qualifying the component for further service. This process will assure that the aging effects, if applicable, are managed such that the components will continue to perform their function through the period of extended operation. Additional information concerning the timing of new inspections is provided in response to RAI G-4.

RAI 4.3.13-2 (12/3/98A)
It is not clear in the application whether the inspections provide for sample expansion or follow-up inspections if unacceptable indications are found. For the stainless steel items within the scope of this program provide additional details regarding follow-up actions where unacceptable indications are found. If sample expansion or follow-up inspections are not included, please justify.

Response to 4.3.13-2
The purpose of the *Treated Water Systems Stainless Steel Inspection* is to determine the applicability of loss of material and cracking of specific portions of those treated water systems addressed in Section 4.3.13 of Exhibit A of the Application. If no indications of loss of material or cracking are identified, the aging effect will be considered not applicable to these systems with this particular material/environment combination. Any indication of loss of material or cracking identified during the *Treated Water Systems Stainless Steel*

Inspection will be evaluated via the Problem Investigation Process (PIP) for acceptability of wall loss. The PIP is governed by a nuclear generation department directive that will initiate an engineering evaluation of the identified condition. The PIP evaluation is designed to consider the need to conduct a root cause analysis and determine corrective actions, which may include actions to prevent recurrence. For this example, the PIP evaluation will determine the need for a root cause analysis, including the establishment of methods to determine the amount of material lost. The piping evaluation will also determine corrective actions that assure a degraded component condition has not or will not exceed the limit required for qualifying the component for further service. These corrective actions may include redesign of the piping segments of concern, material substitution, or the establishment of a new aging management program. If a new program were implemented, the program elements given in Section 4.2 of Exhibit A of the Application would be used to define the program. This process will assure that the aging effects, if applicable, are managed such that the components will continue to perform their function through the period of extended operation.

RAI 4.3.13-3 (12/3/98A)
Please discuss the confirmation process for these inspections, i.e., when corrective actions are completed, the follow up activities performed to confirm that the corrective actions are completed, the root cause determination is performed, and recurrence is prevented. (The discussion of this element in the QA program was not clear, stating that it applied to "more significant events.")

Response to 4.3.13-3
Any indication of loss of material due to pitting corrosion or cracking due to stress corrosion identified during the *Treated Water System Stainless Steel Inspection* will be evaluated using the Problem Investigation Process (PIP). The PIP is governed by a nuclear generation department directive that will initiate an engineering evaluation of the identified condition. The PIP evaluation is designed to consider the need to conduct a root cause analysis and determine corrective actions, including confirmation process, which may include actions to prevent recurrence. For conditions warranting such action, PIP confirms the identified condition has been addressed. For this example, the PIP evaluation will determine the need for a root cause analysis, including the establishment of methods to determine the amount of material lost, and determine corrective actions that assure a degraded component condition did not exceed the limit required for qualifying the component for further service. Additional information about PIP is given in the response to RAI 4.3.9-4.

RAI 4.3.13-4 (12/3/98A)
For these inspections discuss Oconee or applicable industry operating experience from similar programs or inspection techniques used to develop this inspection program.

Response to 4.3.13-4
The purpose of the *Treated Water Systems Stainless Steel Inspection* is to determine the applicability of loss of material and cracking of specific portions of those treated water systems addressed in Section 4.3.13 of Exhibit A of the Application. The inspection is to include a volumetric examination of a length of susceptible piping locations. The examination will include a stainless steel weld and heat affected zone since this is the most likely location for cracking to occur. In addition to the volumetric examination, a visual examination of the interior of a valve will be conducted to determine the presence of pitting corrosion. Volumetric examinations have occurred routinely at Oconee in the *Inservice Inspection Plan*, as well as the *Piping Erosion/Corrosion Program* and *Service Water Piping Corrosion Program*. This method has been proven effective in these programs. Visual examinations also occur routinely. Indications of cracking or pitting can be examined more thoroughly by routine testing such as dye penetrant testing or more advanced failure analysis techniques such as Scanning Electron Microscopy or Energy-Dispersive Spectroscopy in a metallurgical laboratory. These laboratory analyses are available within Duke Energy and are performed routinely for Oconee and other Duke Energy power production facilities.

RAI 4.16-3 (12-04-98A)
Provide a list of surveillance, maintenance, and inspection procedures that are credited with managing the effects of aging for the fire protection systems listed in Section 4.16. Provide a demonstration of how the procedures manage aging effects for fire protection piping and fire barriers.

Response to RAI 4.16-3
The Oconee *Fire Protection Program* is credited with managing the effects of aging for the fire protection systems as described in Section 4.16 and in Selected Licensee Commitment 16.9.5. The *Fire Protection Program* utilizes the concept of defense-in-depth to achieve its required high degree of fire safety. The *Fire Protection Program* contains many activities to achieve this defense-in-depth and to minimize the impacts of a potential fire at Oconee. Two of these activities which are included in the *Fire Protection Program* are:

- Fire Water System Testing
- Fire Barrier Inspections.

The program attributes are implemented through the actions specified in the activities. A correctly defined set of program attributes establishes the framework for an effective aging management program. The demonstration of the effectiveness of these activities is provided in Section 4.16 of Exhibit A of the Application.

In a telephone call on January 12, 1999 between NRC and Duke, the NRC clarified that a list of procedures is less effective than a description of how these procedures are implemented to manage aging. As a result of this discussion, the following information provides examples of how Oconee procedures manage aging effects for fire protection piping and fire barriers.

Fire Water System Testing
For mechanical components, the *Fire Water System Test* looks for and assesses the following aging effects:

- fouling of, particularly, small diameter piping
- loss of material due to a number of corrosion mechanisms.

The fire protection systems include the High Pressure Service Water (HPSW) and Low Pressure Service Water (LPSW) Systems at Oconee, and the Keowee Service Water at Keowee. The *Fire Water System Test* is the title given to the program that encompasses many diverse activities associated with these systems. These activities are performed in accordance with Oconee maintenance procedures. For example, the *Fire Protection-*

Strainer- Grinnell- Removal, Cleaning And Installation procedure provides the criteria and instructions for removing, cleaning, inspecting, and reinstalling strainers in the fire protection systems at Oconee and Keowee. The *Fire Protection Equipment Inspection* and *Keowee Fire Protection Inspection* procedures provide criteria and instructions for inspecting fire protection equipment, such as hose racks, in the fire protection systems at Oconee and Keowee, respectively. The *HPSW Pump Fire Surveillance Performance Test (3 Year Flow Test)* and *HPSW Pump Fire Surveillance Performance Test (Annual Flow Test)* provide an overall system performance test on the HPSW system piping, pumps, and valves. The *Keowee Mulsifyer System Annual Wet Test* provides the equivalent type of test for the Keowee fire protection system.

It is important to note that the aging effects of HPSW, LPSW, and Keowee Service Water are programmatically managed by more that the *Fire Water System Test.* For example, because LPSW serves many safety functions in addition to fire protection functions, fouling in LPSW is managed by *Performance Testing Activities*, not a fire protection-related activity. For a complete understanding of programmatic oversight for particular aging effects in these systems, see Tables 3.5-4 and 3.5-11 of Exhibit A of the Application for LPSW and Keowee Service Water, and the response to RAI 4.16-11 for HPSW.

Overall, the program has been successful in managing fouling and loss of material in the HPSW, LPSW and Keowee Service Water Systems. Full flow testing in comprehensive and includes fire protection systems in the auxiliary building, turbine building, reactor building and the yard loop. Several examples of Oconee operating experience demonstrate the adequacy of the *Fire Water System Test* to manage the aging effects of concern during the period of extended operation. For instance, full flow testing has resulted in cleaning due to fouling of approximately two sprinkler heads at each of the transformers every 18 months. Fouling of the major header has also been detected. Approximately one-eighth inch scaling has been noted on a small section of buried 8 inch piping. However, this minimal degradation was detected well before loss of the system's ability to perform its intended function.

<u>Fire Barrier Inspections</u>
For fire barriers, the *Fire Barrier Inspections* look for and assess the following aging effects:

- Fire barrier penetration seals – cracking, separation from walls or components, separation of layers of material, rupture or puncture of seal.
- Fire barrier walls, ceilings, and floors – loss of material.
- Fire doors – loss of material.

The inspections are performed in accordance with Oconee maintenance procedures. The *Fire Protection – Penetration – Fire Barrier Inspection* procedure provides the criteria and instructions for visually inspecting fire barrier penetrations and fire walls. The *Fire Protection – Fire Rated Doors – Bi-Monthly Inspection* provides the criteria and instructions for visually inspecting fire doors.

A review of the *Fire Barrier Inspections* previously conducted at Oconee confirms the reasonableness and acceptability of the inspections and their frequency in that degradation of the fire barrier was detected prior to loss of function. Identified degradation has been associated with installation problems and has not been associated with aging. Industry experience also validates that the *Fire Barrier Inspections* provide reasonable assurance that the aging effects of fire barriers will be managed so that they will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

RAI 4.16-6 (12/3/98A)
Discuss how fouling is managed/controlled in the fire water system. The submittal states that part of the fire water system is buried. Discuss the materials used in the buried part of the system, i.e., is it coated, and is it cathodically protected.

Response to 4.16-6
The systems that provide fire protection for Oconee are the High Pressure Service Water (HPSW) System, the Low Pressure Service Water (LPSW) System, and the Keowee Service Water System. Fouling in the HPSW and Keowee Service Water Systems are managed by the *Fire Water System Test* of the *Fire Protection Program*. This program is described in Section 4.16.2 of Exhibit A of the Application. Fouling in the LPSW System is managed by the *System Performance Testing Activities*. This program is described in Section 4.27 of Exhibit A of the Application. For a complete understanding of the programmatic oversight for particular aging effects in these systems, see Tables 3.5-4 and 3.5-11 of Exhibit A of the Application for LPSW and Keowee Service Water, respectively, and the response to RAI 4.16-11 for HPSW.

Portions of the HPSW and Keowee Service Water Systems are buried. These components are made of cast iron, are externally coated, and are not cathodically protected. For the aging management review of this portion of these systems, see Section 3.5.2.7.4 of Exhibit A of the Application.

RAI 4.16-10 (12/3/98E)
The following regard the fire water system test program:

a. Are there any buried sections of the high pressure service water system, low pressure service water system and service water system (Keowee)? If yes, how will the corrosion and settlements of supports of the buried piping sections be detected and managed and which aging management programs are you relying on for license renewal? For the above ground portions of the fire water piping system, discuss how the cumulative aging effects on their supports will be managed?

b. With regard to the "Method" of this program, the application only mentions periodic performance or flow tests for piping, pumps, fire hydrants and deluge valves, and visual inspections for hose racks and some sprinkler heads. Provide a description of the methods that are to be used for detecting and managing corrosion (loss of material) of these piping systems and components. The description of these methods should address the detection of cumulative aging effects prior to an observed failure

c. With regard to the "sample size," the application states that "the components that serve a fire protection function within the high pressure service water system, low pressure service water system and Keowee service water system are tested or inspected and maintained on a periodic basis." Are all piping and components of these three systems associated with the fire protection function to be periodically "tested or inspected and maintained" at the same time? If not, what is the sample size for each test and/or inspection and provide the basis for this criteria.

d. On Page 4.16-4, the application states that the inspection and test frequencies are established based on the type of component and managed by plant procedures. It also states that acceptance criteria are specifically stated in the plant procedures that govern each inspection or test. Provide the demonstration that the inspection and test frequencies, and acceptance criteria associated with the current programs are adequate and will address the aging management of cumulative degradation due to aging during the extended period of operation.

Response to 4.16-10
a. As discussed in Sections 2.5.6.4 and 2.5.13.6 of Exhibit A of the Application, portions of the High Pressure Service Water System and the Keowee Service Water System are buried. The Low Pressure Service Water system is discussed in Section 2.5.6.5 of the Application. No portions of the Low Pressure Service Water System are buried.

No supports are provided for the buried portions of the High Pressure Service Water System piping and the Keowee Service Water System piping; therefore, no aging management program is needed for managing aging of supports for buried piping. The piping is supported by compacted earth.

For the above ground piping of the High Pressure Service Water System, Low Pressure Service Water System, and the Keowee Service Water System, the applicable aging effect for the supports is discussed in Section 3.7 of the Application. The supports for the above ground portions of these systems may be located in and exposed to the atmosphere of the Auxiliary Building, Keowee, Reactor Building, Turbine Building, and the yard. Tables 3.7-1, 3.7-4, 3.7-5, 3.7-7 and 3.7-8 identify the aging management program which is credited with managing the aging of the pipe supports located in these structures. Aging effects on the pipe supports are managed by the *Inspection Program for Civil Engineering Structures and Components*. The *Inspection Program for Civil Engineering Structures and Components* is discussed in Section 4.19 of the Application.

b. The *Fire Water System Test* is credited with managing some loss of material mechanisms in some of the components within these systems. For a complete understanding of the programmatic oversight for particular aging effects in these systems, see Tables 3.5-4 and 3.5-11 of Exhibit A of the Application and response to RAI 4.16-11 and the applicable Section 4 description of the programs listed in the tables. Additional description of the *Fire Water System Test* is given in response to RAI 4.16-3.

c. Consistent with the definition in Section 4.2 of Exhibit A of the Application, "sample size" refers to the inspection sample size of a new program only and is not applicable for the *Fire Water System Test*. The "sample size" attribute in the Application should have stated "Not applicable for an existing program." The sentence that is stated in the "sample size" attribute would have better fit as the first sentence of the "frequency" attribute.

d. The *Fire Water System Test* has been successful in managing fouling and loss of material in the High Pressure Service Water, Low Pressure Service Water and Keowee Service Water Systems. Full flow testing in comprehensive and includes fire protection systems in the auxiliary building, turbine building, reactor building and the yard loop. Several examples of Oconee operating experience demonstrate the adequacy of the *Fire Water System Test* to manage the aging effects of concern during the period of extended operation. For instance, full flow testing has resulted in cleaning due to fouling of approximately two sprinkler heads at each of the transformers every 18 months. Fouling of the major header has also been detected. Approximately one-eighth inch scaling has been noted on a small section of buried 8 inch piping. However, this minimal degradation was detected well before loss of the system's ability to perform its intended function.

RAI 4.16-11 (12/3/98E)
Clarify if the fire barrier inspection program and fire water system test program are to be used to detect and manage loss of material, e.g., from corrosion, for the high pressure service water system, low pressure service water system and service water system (Keowee). If not, explain how the loss of material will be detected and managed for these systems, and which program will be credited as an aging management program for the management of this aging effect.

Response to 4.16-11
The *Fire Barrier Inspection Program* is not credited with managing the effects of loss of material in the High Pressure Service Water (HPSW), Low Pressure Service Water (LPSW) or Keowee Service Water Systems. The *Fire Water System Test,* as part of the *Fire Protection Program,* is credited with managing the effects of some loss of material mechanisms in some components of these systems. For a complete understanding of the programmatic oversight for particular aging effects in these systems, see Table 3.5-4 of Exhibit A of the Application for the LPSW System, Table 3.5-11 for the Keowee Service Water System, and the attached tables for the HPSW System. Table 2.5-9 and Table 3.5-4 were provided in the Application for the HPSW System, but many clarifications have been made in response to this request for additional information. The following tables supercede those provided in Exhibit A of the Application for the HPSW System.

Revised Table 2.5-9 of Exhibit A of the Application
Components of Auxiliary Systems and Their Intended Functions
(High Pressure Service Water System)

Mechanical Component	Intended Function(s)	Materials
High Pressure Service Water System		
Annubar Tube	Pressure Boundary	Stainless Steel
Filter	Pressure Boundary	Carbon Steel
Fire Hydrant	Pressure Boundary	Cast Iron
Hose Rack	Pressure Boundary	Bronze
Hose Rack	Pressure Boundary	Carbon Steel
Hose Rack	Pressure Boundary	Stainless Steel
Mulsifyer	Pressure Boundary	Carbon Steel
Orifice	Pressure Boundary	Stainless Steel
Pipe	Pressure Boundary	Carbon Steel
Pipe	Pressure Boundary	Cast Iron
Pipe	Pressure Boundary	Stainless Steel
Pump Casing	Pressure Boundary	Cast Iron
Tubing	Pressure Boundary	Brass
Tubing	Pressure Boundary	Carbon Steel
Tubing	Pressure Boundary	Copper
Tubing	Pressure Boundary	Stainless Steel

Revised Table 2.5-9 of Exhibit A of the Application
Components of Auxiliary Systems and Their Intended Functions
(High Pressure Service Water System)
(continued)

Mechanical Component	Intended Function(s)	Materials
High Pressure Service Water System (continued)		
Sprinkler	Pressure Boundary, Spray	Bronze
Strainer	Pressure Boundary	Cast Iron
Strainer	Pressure Boundary	Carbon Steel
Strainer	Pressure Boundary	Stainless Steel
Valve Bodies	Pressure Boundary	Bronze
Valve Bodies	Pressure Boundary	Carbon Steel
Valve Bodies	Pressure Boundary	Cast Iron
Valve Bodies	Pressure Boundary	Stainless Steel

Revised Table 3.5-4 of Exhibit A of the Application
Applicable Aging Effects for Components of Auxiliary Systems
(High Pressure Water System)

MECHANICAL COMPONENT	MATERIAL	INTERNAL ENVIRONMENT	APPLICABLE AGING EFFECTS	AGING MANAGEMENT PROGRAM/ACTIVITY
High Pressure Service Water System				
Annubar Tube	Stainless Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program
			Fouling	Fire Protection Program
Filter	Carbon Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection
			Fouling	Fire Protection Program
Fire Hydrant	Cast Iron	Air	Loss of Material	Fire Protection Program
Hose Rack	Bronze	Raw Water	Loss of Material	Fire Protection Program
			Fouling	Fire Protection Program
Hose Rack	Carbon Steel	Raw Water	Loss of Material	Fire Protection Program Galvanic Susceptibility Inspection
			Fouling	Fire Protection Program
Hose Rack	Stainless Steel	Raw Water	Loss of Material	Fire Protection Program
			Fouling	Fire Protection Program
Mulsifyer	Carbon Steel	Raw Water	Loss of Material	Fire Protection Program Galvanic Susceptibility Inspection
			Fouling	Fire Protection Program
Orifice	Stainless Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program
			Fouling	Fire Protection Program
Pipe	Carbon Steel	Air	Loss of Material	Fire Protection Program

Revised Table 3.5-4 of Exhibit A of the Application
Applicable Aging Effects for Components of Auxiliary Systems
(High Pressure Water System)
(continued)

MECHANICAL COMPONENT	MATERIAL	INTERNAL ENVIRONMENT	APPLICABLE AGING EFFECTS	AGING MANAGEMENT PROGRAM/ACTIVITY
High Pressure Service Water System (continued)				
Pipe	Carbon Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection
			Fouling	Fire Protection Program
Pipe	Cast Iron	Air	Loss of Material	Fire Protection Program
Pipe	Cast Iron	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection Cast Iron Selective Leaching Inspection
			Fouling	Fire Protection Program
Pipe	Stainless Steel	Air	Loss of Material	Fire Protection Program
Pipe	Stainless Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program
			Fouling	Fire Protection Program
Pump Casing	Cast Iron	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection Cast Iron Selective Leaching Inspection
Tubing	Brass	Raw Water	None identified	None required
Tubing	Carbon Steel	Raw Water	None identified	None required
Tubing	Copper	Raw Water	None identified	None required
Tubing	Stainless Steel	Raw Water	None identified	None required

Revised Table 3.5-4 of Exhibit A of the Application
Applicable Aging Effects for Components of Auxiliary Systems
(High Pressure Water System)
(continued)

MECHANICAL COMPONENT	MATERIAL	INTERNAL ENVIRONMENT	APPLICABLE AGING EFFECTS	AGING MANAGEMENT PROGRAM/ACTIVITY
High Pressure Service Water System (continued)				
Sprinkler	Bronze	Air	Loss of Material	Fire Protection Program
Sprinkler	Bronze	Raw Water	Loss of Material	Fire Protection Program Galvanic Susceptibility Inspection
			Fouling	Fire Protection Program
Strainer	Cast Iron	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection Cast Iron Selective Leaching Inspection
			Fouling	Fire Protection Program
Strainer	Carbon Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection
			Fouling	Fire Protection Program
Strainer	Stainless Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program
			Fouling	Fire Protection Program
Valve Bodies	Bronze	Raw Water	Loss of Material	Service Water Piping Corrosion Program
			Fouling	Fire Protection Program
Valve Bodies	Carbon Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection
			Fouling	Fire Protection Program

Revised Table 3.5-4 of Exhibit A of the Application
Applicable Aging Effects for Components of Auxiliary Systems
(High Pressure Water System)
(continued)

MECHANICAL COMPONENT	MATERIAL	INTERNAL ENVIRONMENT	APPLICABLE AGING EFFECTS	AGING MANAGEMENT PROGRAM/ACTIVITY
High Pressure Service Water System (continued)				
Valve Bodies	Cast Iron	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection Cast Iron Selective Leaching Inspection
			Fouling	Fire Protection Program
Valve Bodies	Stainless Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program
			Fouling	Fire Protection Program

RAI 4.17-2 (12/3/98A)
Describe how the test frequencies and the sampling basis are determined for each heat exchanger type.

Response to 4.17-2
The *Heat Exchanger Performance Testing* is credited with managing fouling in the service water side of the Low Pressure Injection (LPI) Coolers, the Reactor Building Cooling Units (RBCUs) and the heat exchangers in the Standby Shutdown Facility (SSF) Heating, Ventilation, and Air Conditioning (HVAC) Systems. The LPI Coolers and RBCUs are cooled by Low Pressure Service Water. The SSF HVAC Coolers are cooled by the SSF Auxiliary Service Water System.

The LPI Coolers and RBCU heat removal requirements are interdependent. Performance testing is performed each refueling outage on both of these coolers to determine their heat removal capacity. Appropriate heat loads are established and flowrates and delta-temperatures are recorded during the test. The test requires trending of degradation, indicating fouling of the heat exchanger surface. The frequency of the testing has varied over the life of the components but has settled at a refueling outage frequency. This frequency allows for predicted degradation over the fuel cycle to determine that heat removal capability will be maintained at an appropriate level until the next test. Operating experience has proven this frequency effective. Cleaning of several of the LPI Coolers and RBCUs has resulted from indicated degradation (fouling) in these coolers.

The SSF HVAC Coolers are in service at all times. Proper operation of the coolers is required for SSF Power system Operability, per Improved Technical Specifications 3.10.1 D. The coolers are monitored twice per day for proper operation. Any degradation of these coolers will be detected during this activity. This activity has also resulted in cleaning of coolers.

For more information regarding the cleanings of each of these heat exchangers, see the response to RAI 4.17-1.

Consistent with the definition in Section 4.2 of Exhibit A of the Application, "sample size" refers to the inspection sample size of a new program only and is therefore not applicable for this existing program.

RAI 4.25-1 (12/3/98A)
For the planned Keowee inspection for bronze and brass piping, provide the following information: inspection scope, inspection technique (e.g., visual, eddy current, ultrasonic), inspection personnel qualification, inspection timing and frequency (i.e., when is it performed and how often is it performed), acceptance criteria and basis for acceptance criteria, sample size, etc. Discuss the basis for concluding that the above inspection elements will detect degraded conditions for bronze and brass piping before there is a loss of component function.

Response to 4.25-1
The inspection of the bronze and brass piping at Keowee are additional sample points within the *Service Water Piping Corrosion Program.* The *Service Water Piping Corrosion Program* is discussed in Section 4.25 of Exhibit A of the Application. All of the attributes of the *Service Water Piping Corrosion Program* apply to these additional inspection locations. The program is credited in license renewal for managing the aging of a number of systems within the scope of license renewal. The same level of confidence gained from the assessment of the program as an aging management program credited for detecting degraded conditions before there is a loss of component function allows the program to be credited for managing the aging of the Keowee piping systems.

RAI 4.25-2 (12/3/98A)
Section 3.5.9.2 "Condensate System" references the Service Water Piping Corrosion Program. However, it is not explicitly mentioned in the "Purpose" section of 4.25. Confirm that the main condensers and condensate coolers are within the scope of this aging management program.

Response to RAI 4.25-2
Loss of material in the main condensers and condensate coolers is managed by the *Service Water Piping Corrosion Program.* Both coolers contain Condenser Circulating Water System water on the raw water side of the cooler. Although the Condenser Circulating Water System is mentioned in the "Purpose" of Section 4.25 of Exhibit A of the Application, for consistency and clarification, the "Purpose" should have included "Condensate System (raw water side of the main condenser and condensate coolers)" to indicate that this program manages loss of material in these coolers.

RAI 2.5.13-2 (11-20-98F)

a. The Keowee Hydroelectric Station provides a unique emergency power source for Oconee. However, the description of Keowee in the application does not discuss the major components that are necessary for the generation of the emergency power in sufficient detail for the staff to determine whether the appropriate structures and components have been included in the scope of license renewal. Describe in more detail the major components relied upon for the generation of emergency power (for example, the turbine, turbine housing, associated piping, pumps, valves, the generator, synchronizing equipment generator output breakers, control circuitry, protective relaying, the exciter/voltage regulator, and auxiliary power for Keowee Hydroelectric Station) and whether Duke determined these components to be within the scope of license renewal in accordance with 10 CFR 54.4. Otherwise, provide justification of why those components are excluded from the scope of license renewal.

b. In the conference call on November 3, 1998, the licensee indicated that certain Keowee Hydroelectric Station components were determined not to be subject to an AMR. Therefore, the licensee concluded that those components do not need to be addressed in OLRP-1001. For those structures and components determined to be within the scope of license renewal for the Keowee Hydroelectric Station discuss the conclusions reached on whether an AMR should be performed. For example, OLRP-1001 does not address the turbine in the description of Keowee and the flow diagrams listed in Table 2.5-22 do not include the turbine. The staff believes that the turbine is within the scope of license renewal and the turbine casing should be subject to AMR. Therefore, discuss if the turbine is within the scope of license renewal and provide the rationale for excluding the turbine casing from the AMR.

Response to RAI 2.5.13-2

a. All of the systems, structures, and components relied upon for the generation of emergency power from Keowee are within the scope of license renewal in accordance with § 54.4. For mechanical components, the screening process described in Section 2.5.2 of Exhibit A of the Application was then performed on the mechanical components to determine those subject to aging management review. A description of the screening process for structures is given in Section 2.2.1.2 and for structural components in Section 2.7.1 of the Application. A description of the screening process for electrical components is given in Section 2.6 of the Application and in response to RAI 2.6-1. Those components that were not screened out in accordance with § 54.21 are included in the aging management review in the applicable sections of the Application.

Attachment 2A of this letter provides a description and figures of the major components relied upon for the generation of emergency power from Keowee. Attachment 2A is an excerpt from the Keowee Probabilistic Risk Assessment, submitted to the Staff by Duke letter dated June 1, 1995.

b. The components within the highlighted boundaries of the Oconee License Renewal Flow Diagrams (OLRFDs) and Keowee License Renewal Flow Diagrams (KLRFDs) encompass the mechanical components within the scope of license renewal in accordance with § 54.4. The screening process described in Section 2.5.2 of Exhibit A of the Application was then performed on these components to determine the components subject to aging management review. The resulting components are listed in the appropriate tables in Chapter 2 of the Application. In the case of the turbine, it is not shown on the mechanical flow diagrams because it is primarily structural in nature. (See Figure 3.1-2 in Attachment 2A of this letter.) The turbine is not like a conventional steam turbine with a steel casing. It is more like a water wheel encased in the concrete structure that comprises the hydroelectric facility. The rotating turbine is within the scope of license renewal in accordance with § 54.4, but is not subject to aging management review in accordance with § 54.21 because it performs its function with moving parts. The "turbine casing" is actually the concrete substructure of the Keowee powerhouse that is within the scope of license renewal and is subject to aging management review. The results of the aging management review for this structure is presented in Section 3.7.6 of Exhibit A of the Application.

RAI 2.5.13-3 (11-20-98F)
In Drawing No. KLRFD-105A-1.1 (Governor Oil System), the component of governor (Location F14) is highlighted in blue as being within the scope of license renewal. However, in Table 2.5-23, "Components of Keowee Hydroelectric Station Systems and Their Intended Functions," the "governor" is not included. Provide the bases for excluding it.

Response to RAI 2.5.13-3
The components within the highlighted boundaries of the Oconee License Renewal Flow Diagrams (OLRFDs) and Keowee License Renewal Flow Diagrams (KLRFDs) encompass the mechanical components within the scope of license renewal, in accordance with § 54.4. The screening process described in Section 2.5.2 of Exhibit A of the Application was performed on these components to determine the components subject to aging management review. The resulting components are listed in Table 2.5-23. Thus, the components listed in Table 2.5-23 are the components within the scope of license renewal that are subject to aging management review in accordance with § 54.21.

In this case, the governor is within the scope of license renewal, as shown by the KLRFD highlight, but is not subject to aging management review, as indicated by its exclusion from Table 2.5-23. The governor performs its function with moving parts and thus, in accordance with § 54.21, is considered not subject to aging management review. This position is consistent with the finding in NEI 95-10 Appendix B, Revision 0, which lists turbine controls as not passive.

3.0 DESCRIPTION OF KEOWEE GENERATING STATION

3.1 INTRODUCTION

The Keowee generating station is a two unit hydroelectric generating facility, located approximately two-thirds of a mile east-northeast of the Oconee nuclear station. It utilizes water from the 18,000 acre Keowee reservoir through a common penstock to drive the two 96 khp, 128.6 rpm, 87.5 MW_e turbine-generators. Except for the 13.2 kV/230 kV step-up transformer and the penstock, the equipment needed for the power generation and distribution is located inside the Powerhouse.

Keowee is designed to supply the emergency power for Oconee during conditions involving the loss of the normal (Oconee generator) and off-site power for any or all three of the Oconee units. Keowee is also designed to supply power to the Duke 230 kV electrical grid when such grid generation is needed and if there is no emergency power demand for Oconee. When used as the emergency power system, Keowee functions as the on-site power source for Oconee via two separate and independent paths (the overhead path and the underground path). Except for the common penstock and some cooling water piping, each unit is independent of the other. There are interlocks to prevent both units feeding the underground path. Both units can feed the overhead path through the single Keowee step-up transformer, except when the Keowee emergency start signal is present.

Figure 3.1-1 shows a simplified flow path for ac power from the Keowee hydroelectric generators to the Oconee ac power system.

Although Keowee is designed to be operated semi-attended, the station is staffed by an operator at all times.

To generate electric power, each Keowee generator consists of the turbine, the governor, the generator, the exciter/voltage regulator, synchronizing equipment (needed for grid generation only), generator output breakers, control circuitry (for manual and automatic control), protective relaying, and auxiliary power (ac and dc power). The following sections describe these systems in detail. Additional details are provided in Section 4 and Appendix A concerning the reliability modeling of these systems. Figure 3.1-2 presents a simplified functional arrangement of these subsystems to illustrate the Keowee operation.

3.2 TURBINE

The turbine system consists of (1) the rotating elements (turbine runner and the main turbine shaft), (2) the wicket gate assembly, (3) the packing and bearing assembly, (4) the draft tube assembly, and (5) the sump. (See Figure 3.1-2.)

The main turbine shaft is bolted to the generator shaft, and the turbine runner and shaft assembly transform the fluid motion energy into the rotational energy of the turbine as water flows from the penstock through the wicket gate and down through the draft tube.

The wicket gate assembly controls the amount of water flow into the turbine, and thereby the turbine speed and load. This is accomplished by a set of servomotors that move the gate opening and closing arms to achieve the desired speed and load rather rapidly and finely. The servomotors respond to the governor commands for unit start, unit shutdown, load control, and no load operation.

Lubrication and heat removal of the turbine bearings are accomplished by the Turbine Guide Bearing Oil (GBO) system. It is a closed oil system, with an upper and lower oil reservoir. Oil is continuously circulated within the system by pumping the oil from the lower reservoir to the upper reservoir through an oil cooler by an ac pump and a standby dc pump. Water from the Keowee Cooling Water System flows by gravity through the oil cooler and the turbine packing to achieve bearing oil and packing cooling.

The draft tube assembly enables the discharge of the turbine water into the tailrace and creates a low-pressure region to assist the turbine rotation.

Each Keowee unit has a small area known as the wheel pit, located between the generator and turbine. The lower portion of the turbine wheel pit is the sump, which accumulates water leakage from the turbine packing. A set of ac and dc sump pumps is provided to pump the sump water into the sump drain line.

Power (ac and dc) needed by the turbine equipment (bearing oil cooler and sump pumps) is supplied by the Keowee auxiliary power system.

3.3 GOVERNOR

The governor is an electro-mechanical device used to control the position of the wicket gates to allow the turbine speed to match the nominal speed of 128.6 rpm for the full range of load conditions, from no load to full load. The mechanical portion (consisting of springs, pulleys, weights, linkages, and valves) controls oil pressure for the wicket gate servomotor. The electronic portion comprises the solenoids (shutdown solenoid and emergency load solenoid), relays, and switches which interface with the control and protective devices to accomplish the normal operation, emergency power operation, and shutdown.

Supporting the governor are the Governor Oil System and the Governor Air System. The governor oil system supplies oil at 300-350 psi to the governor to control the servomotors. As the oil is used up in the continuous governor operation, it drains into a large oil sump from which it is pumped to the oil pressure tank by three ac powered oil pumps. The air pressure in this oil tank enables a constant circulation of the oil in the governor system. The governor air system simply is a large air receiver which maintains a blanket of pressurized air in the oil tank.

The ac power needed by the oil pumps is supplied by the Keowee auxiliary power system. The normal pressure and oil level in the oil tank are such that the Keowee unit can start and supply loads for some period of time even if all the oil pumps are unavailable. However, as the oil level drops in the tank, the oil volume may not be sufficient to operate the servomotors unless the pumps become operable (within about an hour).

3.4 GENERATOR

The generator assembly is connected to the turbine by the common shaft, bolted at the turbine generator interface. Each generator is a 3-phase, 60 Hertz machine generating power at 13.8 kV, with a rated capacity of 87.5 MVA. It is located immediately below the operating floor of the Powerhouse. It consists of the shaft, the bearing (contained in an oil bath), the generator rotor(field) and stator, and the generator output bus.

Eight oil coolers, with cooling water from the Keowee cooling water system, cool the generator bearing system.

The generator stator is cooled by six air-to-water heat exchangers. Water for these heat exchangers also comes from the Cooling Water System.

An air brake system is used to stop the generator when shutting down. However, it is not needed for the power generation function.

There is a self-contained CO2 fire protection system provided in the generator assembly, and a generator lockout would occur if it actuates. Other protective relaying measures are also used for the generator as described in Section 3.7.

At the top of the generator assembly, a mechanical overspeed trip mechanism is installed to trip the turbine-generator system when the speed approaches unsafe conditions. When the generator trips (mechanical trip setpoint is 180 rpm), it takes several minutes (for the machinery to coast down) and operator action (to reset the overspeed trip) to restart the unit.

The generator excitation and regulation of the output voltage to the set 13.8 kV values are accomplished by the excitation and voltage regulator system.

3.5 EXCITATION/VOLTAGE REGULATION

To transform the mechanical energy of the turbine to electrical energy in the generator, a magnetic field must be supplied. Initially, the electrical input for the excitation field is supplied by the dc auxiliary power system through the field flashing breaker into the field breaker. The field, field flashing, and supply breakers would close on a Keowee start signal. As the generator begins to produce electrical energy, part of it is fed back to the exciter through the field supply breaker to sustain the field. The field flashing breaker opens after a time delay since the external source of field is no longer needed.

The voltage regulator modulates the field density within the generator in such a manner that the voltage of the generator electrical output matches the design value of 13.8 kV, within acceptable tolerances.

3.6 GENERATOR OUTPUT BREAKERS

The generator output breakers provide the interface between the generator and the power transmission line or bus. There are two output breakers for each unit: Air Circuit Breakers (ACBs) 1 and 3 for Unit 1 and ACBs 2 and 4 for Unit 2. ACBs 1 and 2 connect the generators to the Keowee 13.2 kV/230 kV step-up transformer, from which the Keowee power can feed the grid through PCB-8 or it can energize the Keowee overhead path to Oconee through PCB-9, the 230 kV switchyard yellow bus, and the Oconee start-up transformer(s).

ACBs 3 and 4 connect the Keowee units to the Keowee underground emergency power path to Oconee. Normally, one of the Keowee units is pre-assigned to the underground path, and its underground path breaker is kept closed while the other unit's breaker is left open. These breakers are interlocked to prevent both breakers being simultaneously closed onto the underground path.

When the Keowee units are started for grid generation, ACBs 1 and 2 close automatically. If a Keowee emergency power demand occurs at this time, these breakers will open, the turbine generators are controlled in the no-load mode, and then will energize the underground path up to CT4. If necessary (only if the event involves a loss of off-site power), the overhead path is energized by closing the overhead path breakers. The ACB (and PCB-9) closing logic contains a feature to confirm the yellow bus isolation is complete (PCBs 8, 12, 15, 17, 21, 24, 26, 28, and 33 are open). The ACB close is also controlled by delay times to prevent the units' energizing the Keowee transformer out of phase.

At the time of this study, the Keowee unit dedicated to the underground path is not allowed to feed the grid on an interim basis until certain single failure issues are resolved. Thus, when the unit starts up on an emergency demand, it energizes the underground path to allow loading in about 12 seconds. The other unit remains in a standby mode unless the normal switchyard power is lost, in which case the overhead path ACB closes after a time delay (~4 seconds for ACB-2 and ~6.5 seconds for ACB-1) to allow the affected Oconee unit's start-up bus to trip the non-essential 6.9 kV buses.

3.7 KEOWEE EMERGENCY START AND CONTROL

The start-up equipment for Keowee is located in the Keowee Control and Battery Rooms. The signals for automatic emergency start of the units originate from each Oconee unit (engineered safeguards actuation or loss of MFB power) and also from the Oconee 230 kV switchyard (EGTPS) through the Oconee electrical equipment room. The units can also be started manually in the emergency mode from the Oconee Control Rooms, or the Oconee cable rooms. The Oconee signals and control cables pass through the underground trench. Keowee station alarms are annunciated in the Keowee Control Room, while the critical alarms and controls are also provided in the Oconee Control Rooms.

For each Keowee unit, there are redundant channels (Channels A and B) and diverse means to detect a loss of power condition, process the signals, and initiate the emergency start function. Upon actuation, the emergency start auxiliary relays, located at Keowee, allow the field supply breakers to close and energize two master relays, one of which energizes the governor shutdown solenoid relays, and the other starts the equipment needed for lubrication and cooling.

3.8 PROTECTIVE RELAYING

Fault conditions of the power equipment and the power circuits are monitored and the faults are isolated by a variety of protective relays. Fault protection is provided for the generators, the transformers, and the bus work by means of the zone protection scheme.

The lockouts generated by these protection features could prevent the unit start. During an emergency start condition, only an emergency lockout can prevent the unit start, since the normal lockouts are bypassed under this condition. The reliability model includes failure modes of the relays whose spurious operation can create a Keowee failure due to spurious fault indications.

3.9 AUXILIARY POWER

The Keowee auxiliary power system comprises the 125 V dc power system and the 600 V and 208 V ac power system which are needed to operate the equipment needed for the Keowee start and power operation.

Each unit has a dc power system, consisting of a battery, battery charger and dc distribution bus. It enables the unit to start under a loss of all ac power condition, providing instrumentation and control power and dc power needed by the dc motors. The dc distribution system can be cross-connected between the units to

facilitate battery maintenance. A standby charger is also available should one of the two normal chargers be out of service.

The ac portion of the auxiliary power system is also unit-specific, with the capability to cross-connect should the normal ac power bus for a Keowee unit be unavailable. AC power is needed for extended operation (more than an hour) of Keowee to charge the batteries, to operate the oil pumps, etc.

There are three transformers which can power the 600 V ac auxiliary power switchgear centers 1X and 2X of Keowee 1 and Keowee 2:

- the 4160/600 V CX transformer powered by the 1TC Oconee switchgear,
- the 13.8 kV/600 V 1X transformer powered by the Keowee main transformer, or
- the other 13.8 kV/600 V transformer (2X) powered by the Keowee main transformer.

Transformer CX is the primary source of auxiliary power for the Keowee unit assigned to the underground path. If this power source fails, the load center automatically transfers to the backup source, the auxiliary transformer off the Keowee transformer.

For the unit being used for the overhead path, the primary auxiliary power source is the auxiliary transformer off the Keowee transformer. If this source is unavailable, an automatic transfer to Transformer CX would occur.

Transformers 1X and 2X are normally energized by the grid through the 230 kV switchyard and the Keowee main transformer. With a loss of off-site power, the Keowee unit not operating on the underground path would energize these transformers with its overhead path ACB closed to the Keowee main transformer.

The 600 V ac auxiliary power switchgear centers can also be manually energized by opening and closing certain auxiliary power ACBs. Each units' motor control center can be cross-connected to the other unit's switchgear.

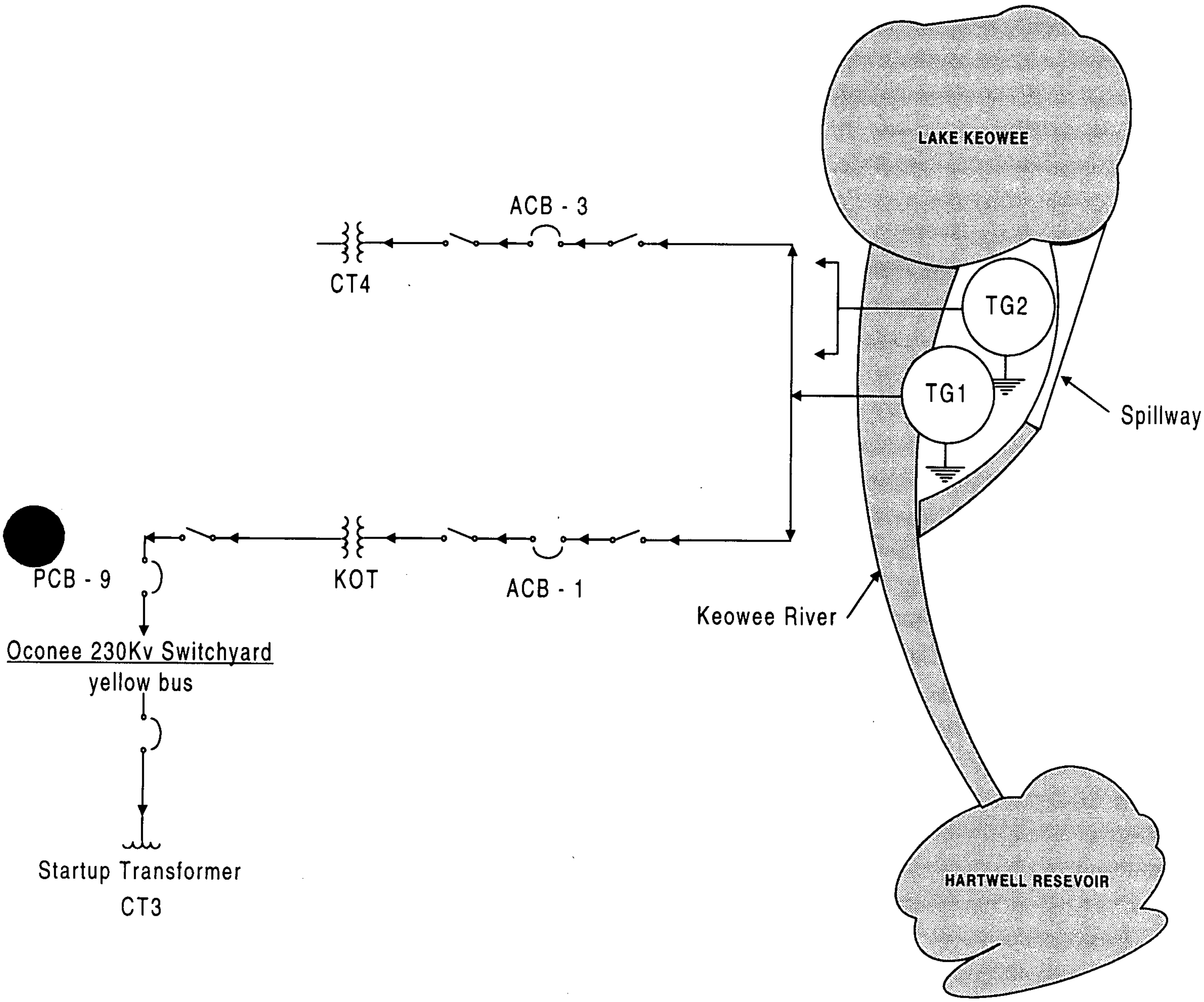

Figure 3.1-1 Rev. 0 Keowee - Oconee AC Power Flowpath

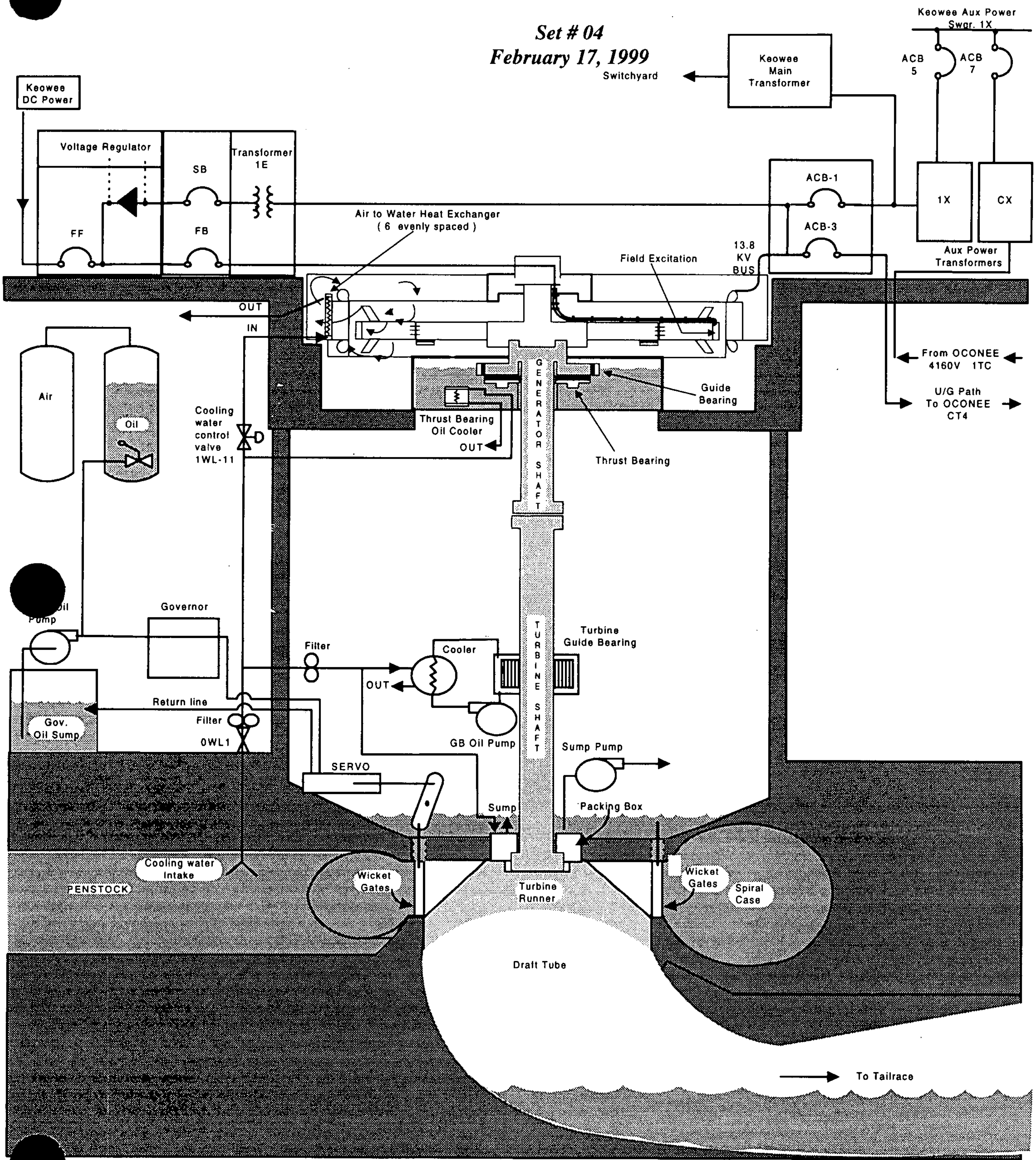

Figure 3.1-2 Rev. 0 Keowee Subsystems Needed For Oconee AC Power

ATTACHMENT 3
Oconee Nuclear Station
Application for Renewed Operating Licenses
Responses to NRC Requests for Additional Information (RAI)

Set # 04
February 17, 1999

RAI 2.6-1 (11/25/98A)
Section 2.6.1 of the application describes the scoping process to identify electrical components subject to an aging management review. This scoping process is based on installed location first and then system function. This differs from the mechanical scoping process, which evaluates systems, structures, and components based on 10 CFR 54.4 (a)(1), (2), and (3) criteria. As such, the electrical component scoping is highly dependent upon the accuracy of the identification of Class 1, Class 2, and Class 3 structures to identify the scope of electrical components for license renewal.

With the above electrical component scoping process discuss how the list of electrical components subject to an aging management review is determined to be complete and accurate.

In addition, provide a list of the license renewal basis documents that were used for scoping based on location and system function including summary information from each document that supports the process and methodology for electrical scoping.

Response to RAI 2.6-1
This RAI has two aspects:

- The order of the electrical scoping steps and the differences between the mechanical and electrical scoping processes, and
- The accuracy of using in-scope structures to identify the areas containing electrical components within the scope of license renewal.

These two aspects are discussed separately.

In a Trip Report dated February 8, 1999, the staff provides a summary of its review activities performed at the Duke offices from October 27, 1998 to October 30, 1998. The staff observed that the electrical system scoping and component screening process was confusing and difficult to follow. Several specific observations are made which resulted in several staff RAIs.

Duke recognizes that the previous description of the electrical process is confusing and difficult to follow. To address these staff observations, as well as to respond to RAI 2.6-1, Duke has revised the description of the method used in the IPA to address electrical component scoping and screening. This revised description is intended to be readily understandable to any knowledgeable reader. The following are the main topics contained in this RAI response:

THE ORDER OF THE ELECTRICAL SCOPING STEPS AND THE DIFFERENCES BETWEEN THE MECHANICAL AND ELECTRICAL SCOPING PROCESSES

The method used in the integrated plant assessment to address electrical components is organized based on components. The electrical process seems much different than the method used for mechanical components but the differences are minimal. The main differences in these two approaches include (1) the order in which the steps are performed and (2) electrical systems are not identified.

In designing the electrical scoping and screening process, Duke realized that many electrical component commodity groups are not identified in NEI 95-10 Rev. 0 and the criteria of §54.21(a)(1)(i) is not applied to these unidentified commodity groups as well as some components that are identified in NEI 95-10 Rev. 0. Without this information being documented in NEI 95-10 Rev. 0, these identifications and determinations are made on a plant specific basis which requires the §54.21(a)(1)(i) screening step to be somewhat lengthy. Once these additional components and their §54.21(a)(1)(i) determinations are included in NEI 95-10, this will not need to be performed in plant specific IPAs.

Duke also realized that most electrical components do not meet the criteria of §54.21(a)(1)(i). Of the 50 electrical component commodity groups identified for Oconee, only nine (9) are determined to meet the criteria of §54.21(a)(1)(i). If steps were performed in the same order as that done for mechanical components (i.e., scoping then screening), significant resources would be expended making scoping determinations for electrical components that are ultimately screened out (i.e., the component meets the §54.4(a) criteria but does not meet the §54.21(a)(1)(i) criteria).

In addition, Duke realized that the internal mechanical component environments normally have more significance for aging. This is in contrast to electrical components whose external environments normally have more significance for aging. Many electrical components, such as cables, are installed in common, plant areas, and are exposed to the same or similar external (ambient) environments. External, ambient environmental information is needed for all electrical components included in the aging management review. With this in mind, dividing electrical components into their respective systems was not seen as being necessary for performing the aging management review.

These considerations, in conjunction with the aim of developing a complete and accurate list that includes electrical components subject to an aging management review, led to the a process in which the order of the §54.4(a) scoping and §54.21(a)(1)(i) screening steps is different than the mechanical component process. Overviews of the mechanical and electrical scoping processes are provided below along with a comparison.

Mechanical Scoping Process
A list of mechanical systems is generated and systems that perform a §54.4(a) intended function are identified. Using this list of systems, mechanical flow diagrams are marked to show the license renewal evaluation boundaries. With the boundaries drawn, mechanical components meeting the §54.21(a)(1)(i) and (ii) criteria within these boundaries are identified. Therefore, the basic process for mechanical components is §54.4(a) scoping followed by §54.21(a)(1)(i) and (ii) screening.

Electrical Scoping Process
A complete list of electrical component commodity groups is developed and then the §54.21(a)(1)(i) screening is documented for each commodity group. Next, scoping is performed in a very selective manner. Only selected groups of electrical components are scoped using the criteria of §54.4(a) and all electrical components not part of the groups selected for scoping are included in a broader scope of review as part of an encompassing group. An encompassing group of components is a defined group that includes both electrical components that meet the §54.4(a) criteria and electrical components that may not meet the §54.4(a) criteria. All electrical components meeting the criteria of §54.21(a)(1)(i) are either scoped or are included in an encompassing group. The last step is to identify any components that do not meet the criteria of §54.21(a)(1)(ii). Therefore, the basic process for electrical components is §54.21(a)(1)(i) screening followed by §54.4(a) scoping and then §54.21(a)(1)(ii) screening.

Comparison of the Processes

Both of the processes reach the same end of identifying the specific components, or an encompassing group of components, to be included in the aging management review.

One difference in the processes is the order in which the screening and scoping steps are performed. A component, to be subject to an aging management review, must meet all three of the scoping and screening criteria — §54.21(a)(1)(i), §54.4(a), and §54.21(a)(1)(ii). When a component does not meet any one of these criteria, the component is not subject to an aging management review. The order in which these criteria are applied does not alter which components are subject to an aging management review.

Another difference in the processes is that the mechanical scoping process identifies and scopes all mechanical systems and the electrical process only scopes selected electrical components. Electrical components that are not selected for scoping are included in a broader scope of review as part of an encompassing group. Regarding the identification of an encompassing group of components, the statement of considerations (SOC) for 10 CFR 54 states:

SOC to 10 CFR Part 54, Section III.f.(ii)

A licensee has the flexibility to determine the set of structures and components for which an aging management review is performed, provided that this set encompasses the structures and components for which the Commission has determined an aging management review is required for the period of extended operation. Therefore, a licensee's aging management review must include structures and components --

(1) That were not subject to replacement based on a qualified life or a specified time period; and

(2) That perform an intended function (§54.4) without moving parts or without a change in configuration or properties.

In establishing this flexibility, the Commission recognizes that licensees may find it preferable to not take maximum advantage of the Commission's generic conclusion regarding structures and components that do not require an aging management review, and may undertake a broader scope of review than is minimally required. For example, a licensee may desire to review all 'passive' structures and components. This set of structures and components would be acceptable because it includes 'long-lived' as well as periodically replaced structures and components and, therefore, encompasses all structures and components that would be identified through criteria (1) and (2) above. (emphasis added)

Identifying and including an encompassing group of components in the scope of review is an acceptable option.

Section 4.1 of NEI 95-10 Rev. 0 gives the following guidance on the identification of components subject to an aging management review:

> **NEI 95-10 Rev. 0, Section 4.1**
>
> *There are a number of different methods that will accomplish the same objective of identifying structures and components subject to an aging management review. Regardless of the method used, it must produce the identification and listing of structures and components required by §54.21(a)(1)(i) and (ii). (Figure 4.1-1 reflects the method described in this section.)*
>
> *Selection of an appropriate method is highly dependent on the applicant's information management system(s). For example, the availability of computer databases of plant equipment may result in a more efficient component-by-component review process. Absent such databases, an applicant may use a manual review process based on system piping and instrumentation drawings and electrical one-line diagrams supplemented by other available plant documentation as required.*
>
> *As a minimum, the resulting list developed by the applicant must include all passive, long-lived structures and components (or commodity groupings) within the scope of license renewal. However, if an applicant chooses for its own reason, the list could be larger (e.g., all passive structures and components).*

In summary, the main differences in the electrical and mechanical scoping processes include (1) the order in which the steps are performed and (2) electrical systems are not identified. Different processes are allowed within the requirements of §54 and different processes can produce complete and accurate results.

THE ACCURACY OF USING IN-SCOPE STRUCTURES TO IDENTIFY THE AREAS CONTAINING ELECTRICAL COMPONENTS WITHIN THE SCOPE OF LICENSE RENEWAL

Using in-scope structures to identify the areas containing electrical components within the scope of license renewal is described in Section 2.6.7 of Exhibit A of the Application. In subsequent meetings with the NRC staff on October 22, 1998, and the week of October 26, 1998, concerns were raised as to the accuracy of such an approach. Staff concerns are further exhibited in the several RAIs related to this topic.

Although Duke continues to believe that using in-scope structures to identify the areas containing electrical components within the scope of license renewal is valid and can produce accurate results, Duke also recognizes that this approach has added complexity to the staff reviews of Exhibit A of the Application. Therefore, Duke is opting for a more conservative approach that no longer eliminates electrical components from the aging management review based on their being supported by a specific class of structure. No other scoping or screening process changes are made.

Details of Duke's electrical component screening and scoping process are provided below which incorporates the scoping process changes identified above.

SUMMARY OF ELECTRICAL COMPONENT SCREENING & SCOPING

As an overview, RAI Response Table 2.6-1 provides a summary of electrical component screening and scoping. This table identifies the starting point of the integrated plant assessment, shows the result of the application of each of the §54.21(a)(1)(i), §54.4(a), and §54.21(a)(1)(ii) criteria, and provides the results – the electrical components subject to an aging management review. The following paragraphs describe each column of the table along with the bases for the information presented in each column. RAI Response Table 2.6-1 appears at the end of these column descriptions.

Column 1 of RAI Response Table 2.6-1 — Electrical Component

The electrical component integrated plant assessment starts with all Oconee electrical components organized into electrical component commodity groups. The method used to identify all electrical components started with a review of industry license renewal component lists (i.e., §54.21(a)(1)(i) and NEI 95-10 Rev. 0 Appendix B) and a review of Oconee electrical system drawings. The composite list was reviewed by electrical power and I&C experts at Duke's general offices and at Oconee and was reviewed by individuals in an industry license renewal electrical peer group. This iterative process included multiple reviews by many individuals. Using Oconee and industry information along with reviews by electrical experts and industry peers provides reasonable assurance that the list of electrical components is complete and accurate. This process resulted in the list of electrical component commodity groups identified in Column 1 of RAI Response Table 2.6-1.

Column 2 of RAI Response Table 2.6-1 — §54.21(a)(1)(i) Criteria Are Met

Column 2 provides the results of the application of the criteria of §54.21(a)(1)(i) to the components identified in Column 1. A "Yes" in Column 2 of RAI Response Table 2.6-1 indicates that the component meets the §54.21(a)(1)(i) criteria (i.e., the component performs its intended function without moving parts or without a change in configuration or

properties). A "No" in Column 2 indicates that the component *does not* meet the §54.21(a)(1)(i) criteria and is not subject to an aging management review.

Information provided in this section is intended to also address aspects of RAI 2.6-6, RAI 2.6-9, and RAI 2.6.1-3.

Three documents are initially used for identifying electrical components that meet the criteria of §54.21(a)(1)(i): 10 CFR 54 (§54.21(a)(1)(i)), NEI 95-10 Rev. 0 Appendix B, and the September 19, 1997, NRC letter to NEI [Reference 2.6-3 of Exhibit A of the Application]. The following table identifies the reference document for each §54.21(a)(1)(i) determination agreed with and credited by Duke:

Reference Document	Electrical Components Whose §54.21(a)(1)(i) Determination in the Reference Document is Credited by Duke
§54.21(a)(1)(i)	batteries, electrical cables and connections (i.e., insulated cables and connections, transmission conductors, uninsulated ground conductors), chargers (e.g., battery chargers), circuit boards and transistors (i.e., solid-state devices), breakers (i.e., circuit breakers), electrical penetration assemblies, generators (e.g., diesel generators), indicators (e.g., pressure indicators, water level indicators), inverters (e.g., power inverters), motors, power supplies, relays, switches, switchgear, transmitters (e.g., pressure transmitters)
NEI 95-10 Rev. 0, Appendix B	alarm, analyzers, annunciators, converters (e.g., voltage/current, voltage/pneumatic), electrical controls and panel internal component assemblies, elements (e.g., conductivity elements, flow elements), isolators, load centers, loop controllers (e.g., differential pressure indicating controller, flow indicating controller, temperature controller, speed controller), meters (e.g., ammeter), motor control centers, power distribution panels, radiation monitors, recorders, sensors (e.g., temperature sensors, radiation sensors), signal conditioners, solenoid operators, transducers (e.g., watt transducer)
September 19, 1997, NRC letter to NEI	heat tracing, heaters, indicating lights (i.e., light bulbs), transformers

Several types of electrical components are not identified in these reference documents. Duke also does not agree with the §54.21(a)(1)(i) determinations made for some electrical components. Duke provides the §54.21(a)(1)(i) determinations and their bases for both of these sets of electrical components. These components are identified in the table below.

Electrical Components For Which Duke Made a §54.21(a)(1)(i) Determination
fuses, RTDs, thermocouples, insulators, isolated-phase bus, nonsegregated-phase bus, segregated-phase bus, switchyard bus, communication equipment, regulators, surge arresters

The §54.21(a)(1)(i) determination for these electrical components is provided below.

- **Fuses**

Fuses do not meet the criteria of §54.21(a)(1)(i). The details of this determination are in Section 2.6.6.7 of Exhibit A of the Application.

- **RTDs, Thermocouples**

RTDs and thermocouples do not meet the criteria of §54.21(a)(1)(i). The details of this determination are in Sections 2.6.6.5 and 2.6.6.6 of Exhibit A of the Application with additional information provided in the Response to RAIs 2.6-6 and 2.6-7.

- **Insulators, Isolated-Phase Bus, Nonsegregated-Phase Bus, Segregated-Phase Bus, Switchyard Bus**

These components perform their intended function without moving parts and without a change in configuration or properties. Therefore, these components meet the criteria of §54.21(a)(1)(i).

- **Communication Equipment**

The intended function of communication equipment is to permit the interchange of information. This commodity group includes any number of components that are used to send or receive communication signals including such things as telephones, intercoms, video or audio recording or playback equipment, electronic messaging, radios, and power-line carrier equipment. These communication devices involve processes such as conversions between audible or visible energy and electrical energy, and the transmission and receiving of electrical or electromagnetic signals. These processes produce physical property changes in the equipment that are readily detectable as audible or visible energy. Therefore, communication equipment does not meet the criteria of §54.21(a)(1)(i).

- **Regulators**

The intended function of a regulator is to vary or prevent variation in a desired characteristic. The regulators addressed here are those considered to be a separate piece of equipment and not a part of a larger component. At Oconee, this group consists of voltage regulators that provide power to regulated power panelboards. These regulators are autotransformers with several different taps. The output voltage is kept constant (or within a specified range) by changing the transformer tap based on the input voltage. The tap changes are circuit configuration changes within the regulator that are performed by automatically controlled switches. This automatic switching is an electrical circuit configuration change that is directly related to the intended function of a regulator; i.e., a regulator performs its intended

function by a change in configuration. Therefore, regulators do not meet the criteria of §54.21(a)(1)(i).

- **Surge Arresters**

Surge arresters are devices used to limit surge voltages and currents on electrical circuits and include components such as lightning arresters, surge suppressers, surge capacitors, and protective capacitors. The surge arresters addressed here include high voltage surge arresters that are large enough to be considered a separate piece of equipment and are not a part of some larger component. At Oconee, surge arresters are used in applications associated with large motors, the unit generators, large transformers, and transmission lines.

Surge arresters perform their intended function through a change in state similar to transistors, which is excluded in §54.21(a)(1)(i) from an aging management review. Surge arresters are constructed of either silicon carbide or metal oxide. These are both semiconducting materials that exhibit a very large resistance at lower (normal system) voltages and a very low resistance at high (surge) voltages. Surge arresters may also have gaps built in to help discharge the surge voltage. At normal system voltage, the arrester exhibits a very large resistance and behaves like an insulator with very little leakage current (no leakage if the design also has gaps). When a voltage surge is encountered, the resistance of the material decreases and a surge arrester behaves like a short circuit, discharging the surge to ground. After the surge passes, the arrester material reverts to its high resistance and reseals the circuit. A surge arrester uses these changes in material properties to perform its intended function in the same way that solid-state devices perform their intended function of controlling current using electric or magnetic phenomena in solids. Therefore, surge arresters do not meet the criteria of §54.21(a)(1)(i).

Column 3 of RAI Response Table 2.6-1 — Application of §54.4(a) Criteria

Column 3 provides the results of the application of the criteria of §54.4(a) to the electrical components that meet the criteria of §54.21(a)(1)(i).

Information provided in this section is intended to also address aspects of RAI 2.6-2, RAI 2.6.1-1, RAI 2.6.1-2, RAI 2.6.1-3, RAI 2.6.7-1, and RAI 2.6.7-2.

All electrical components fall into one of the following scoping categories:

1. **Selected groups of electrical components that are demonstrated not to meet the criteria of §54.4(a)** - Electrical components selected for scoping are those associated with the (A) 525 kV Switchyard, (B) Jocassee, Calhoun, Oconee, and Dacus 230 kV transmissions lines, (C) Radwaste Facility, and (D) Oconee Retail substation. As demonstrated later in this section, these electrical components do not meet the criteria of

§54.4(a) and are not included in the aging management review. §54.4(a) allows scoping by systems, structures, or components.

2. **Electrical components that are designated as QA Condition 1 -** These components meet the criteria of §54.4(a) and are included in the scope of review.
3. **Electrical components that are not designated as QA Condition 1 and are not in the selected groups identified in category 1 above -** These electrical components may or may not meet the criteria of §54.4(a) but are included in the scope of review as part of an encompassing group.

Only the groups of electrical components identified in category 1 above are eliminated from the aging management review via the criteria of §54.4(a). Many other electrical components that do not meet the criteria of §54.4(a) are included in the scope of review as part of an encompassing group. The basis for the determination that the groups of electrical components identified in category 1 above do not meet the criteria of §54.4(a) is provided below. Following the scoping of these selected groups of electrical components, there are scoping discussions for the electrical component commodity groups that meet the criteria of §54.21(a)(1)(i).

A study was conducted which reviewed the information generated by the Oconee Safety-Related Designation Clarification (OSRDC) project. The OSRDC project clarified the Oconee QA Condition 1 licensing basis, clarified the Oconee licensing basis with respect to design basis event mitigation requirements, and identified important non-QA Condition 1 systems and components. Further details of the OSRDC project are contained in the Response to RAI 2.2-6. The results of this study are used to validate the scoping of electrical components.

Scoping discussions for the selected groups of electrical components are provided below.

(A) Scoping of Electrical Components Associated with the 525 kV Switchyard
Oconee UFSAR Section 8.2.1.2 describes the 525 kV Switchyard. Oconee Unit 3 generates electric power to the 525 kV Switchyard. Three transmission lines connect the 525 kV Switchyard to the Duke transmission grid. In addition, a 230/525 kV autotransformer connects the 525 kV Switchyard to the 230 kV Switchyard.

The 525 kV Switchyard and its associated equipment (including all other equipment operating at 525 kV) do not perform or support any of the functions identified in §54.4(a)(1). The 525 kV Switchyard and its associated equipment are not relied upon to remain functional during or following any design basis event. This conclusion is validated by a study of the OSRDC project results (See the Response to RAI 2.2-6 for details of the OSRDC project). Unit 3 generates power to the 525 kV Switchyard but the assured power

source for Unit 3 is the Keowee Hydroelectric Station through the underground or overhead power paths. No failure of the 525 kV Switchyard or its associated equipment will prevent satisfactory accomplishment of any functions identified in §54.4(a)(1). Loss of any 525 kV equipment or transmission lines will not adversely affect the operation of the 230 kV Switchyard or any other equipment relied upon during or following any design basis event.

The 525 kV Switchyard and its associated equipment are not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection, pressurized thermal shock, or anticipated transients without scram. The 525 kV Switchyard and its associated equipment are not included in the Oconee EQ program and no credit is taken for the 525 kV Switchyard or its associated equipment to address station blackout. Therefore, the 525 kV Switchyard and its associated equipment are not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), or station blackout (10 CFR 50.63).

The 525 kV Switchyard and its associated equipment do not meet the criteria of §54.4(a) and are not subject to an aging management review.

(B) Scoping of Electrical Components Associated with the Jocassee, Calhoun, Oconee, and Dacus 230 kV Transmission Lines

The Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines serve to connect Oconee with the remainder of the Duke 230 kV transmission system. The Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines are shown on the simplified one-line diagram of the Oconee 230 kV Switchyard in Figure 2.6-4 of Exhibit A of the Application.

The Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines do not perform or support any of the functions identified in §54.4(a)(1). The emergency power source for the Oconee units is Keowee, which can feed power to Oconee via an underground cable or via an overhead power path through a portion of the 230 kV Switchyard. When used for emergency power, the overhead power path is isolated from the remainder of the 230 kV Switchyard, which also isolates overhead power path from the Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines. The Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines are not relied upon to remain functional during or following any design basis event. This conclusion is validated by a study of the OSRDC project results (See the Response to RAI 2.2-6 for details of the OSRDC project). No failure of the Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines will prevent satisfactory accomplishment of any functions identified in §54.4(a)(1). Loss of the Jocassee, Calhoun,

Oconee, or Dacus 230 kV transmission lines will not adversely affect the operation of the 230 kV Switchyard or any other equipment relied upon during or following any design basis event.

The Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines are not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection, pressurized thermal shock, or anticipated transients without scram. The Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines are not included in the Oconee EQ program. Loss of all these 230 kV transmission lines may play some role in the initiation of a station blackout event, but, as stated in Section III, *Review Procedures*, of the September 1997 Working Draft of the Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants:

> *"A system, structure, and component whose operation or failure is assumed to be the initiator of the event or is assumed to make the event more severe need not be identified as within scope of license renewal."*

No credit is taken for the Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines to address station blackout. Therefore, the Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines are not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), or station blackout (10 CFR 50.63).

The Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines do not meet the criteria of §54.4(a) and are not subject to an aging management review.

(C) Scoping of Electrical Components Associated with the Radwaste Facility
The Radwaste Facility is designed to process radioactive waste before shipment offsite and serves no function related to the generation of power or the operation of the reactor. The Radwaste Facility does not perform or support any of the functions identified in §54.4(a)(1). The Radwaste Facility is not relied upon to function during or following any design basis event. This conclusion is validated by a study of the OSRDC project results (See the Response to RAI 2.2-6 for details of the OSRDC project). No failure of the Radwaste Facility or any Radwaste Facility equipment will prevent satisfactory accomplishment of any functions identified in §54.4(a)(1).

The Radwaste Facility is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection, pressurized thermal shock, or anticipated transients without scram. The

Radwaste Facility and none of its equipment is included in the Oconee EQ program and no credit is taken for the Radwaste Facility to address station blackout. Therefore, the Radwaste Facility and its associated equipment are not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), or station blackout (10 CFR 50.63).

The Radwaste Facility does not meet the criteria of §54.4(a) and is not subject to an aging management review.

(D) Scoping of Electrical Components Associated with the Oconee Retail Substation
Oconee Retail is a 44 kV substation that is used to deliver retail power to the Oconee site. The power supplied from the Oconee Retail substation feeds normal site loads and does not feed any unit loads related to power generation. The Oconee Retail substation does not perform or support any of the functions identified in §54.4(a)(1). The Oconee Retail substation is not relied upon to function during or following any design basis event. This conclusion is validated by a study of the OSRDC project results (See the Response to RAI 2.2-6 for details of the OSRDC project). No failure of the Oconee Retail substation or any Oconee Retail substation equipment will prevent satisfactory accomplishment of any functions identified in §54.4(a)(1).

The Oconee Retail substation is not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection, pressurized thermal shock, or anticipated transients without scram. The Oconee Retail substation and none of its equipment is included in the Oconee EQ program and no credit is taken for the Oconee Retail substation to address station blackout. Therefore, the Oconee Retail substation and its associated equipment are not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), or station blackout (10 CFR 50.63).

The Oconee Retail substation does not meet the criteria of §54.4(a) and is not subject to an aging management review.

NOTE: *This completes the scoping of the selected groups of electrical components. Next are scoping discussions for electrical component commodity groups meeting the criteria of §54.21(a)(1)(i).*

- **Electrical Penetration Assemblies**

All electrical penetration assemblies are included in the Oconee EQ program and all installed electrical penetration assemblies are relied upon in safety analyses and plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for environmental qualification (10 CFR 50.49). Therefore, all electrical penetration assemblies meet the criteria of §54.4(a).

- **Insulated Cables and Connections**

Numerous insulated cables and connections installed at Oconee perform or support §54.4(a) intended functions and numerous insulated cables and connections do not perform or support §54.4(a) intended functions. Duke has determined that insulated cables and connections associated with the 525 kV Switchyard, Radwaste Facility, and Oconee Retail substation do not meet the criteria of §54.4(a). An encompassing group of all insulated cables and connections except those associated with the (a) 525 kV Switchyard, (b) Radwaste Facility, or (c) Oconee Retail substation is included in the scope of review.

- **Insulators**

Numerous insulators installed at Oconee perform or support §54.4(a) intended function and numerous insulators do not perform or support §54.4(a) intended functions. Duke has determined that insulators associated with the 525 kV Switchyard, Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines, and Oconee Retail substation do not meet the criteria of §54.4(a). An encompassing group of all insulators except those associated with the (a) 525 kV Switchyard, (b) Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines, or (c) Oconee Retail substation is included in the scope of review.

- **Isolated-phase Bus**

Isolated-phase bus is used at both Keowee and Oconee. Keowee isolated-phase bus is used to connect the main switchgear of each unit to the Keowee main step-up transformer. Oconee isolated-phase bus is used to connect each unit generator to its main step-up transformer and unit auxiliary transformer. Keowee isolated-phase bus is designated as QA Condition 1 and meets the criteria of §54.4(a). Oconee isolated-phase bus is not designated as QA Condition 1, but is included in the scope of review as part of an encompassing group. An encompassing group of all isolated-phase bus is included in the scope of review.

- **Nonsegregated-phase Bus**

Nonsegregated-phase bus is used in the Oconee 4160V and 6900V power systems. Oconee 4160V nonsegregated-phase bus is used to connect QA Condition 1 switchgear and meets the criteria of §54.4(a). Oconee 6900V nonsegregated-phase bus is used to connect the unit auxiliary and start-up transformers to the reactor coolant pump switchgear and is included in

the scope of review as part of an encompassing group. An encompassing group of all nonsegregated-phase bus is included in the scope of review.

- **Segregated-Phase Bus**

Segregated-phase bus is used at Keowee and is designated as QA Condition 1. Therefore, segregated-phase bus meets the criteria of §54.4(a).

- **Switchyard Bus**

Some switchyard bus at Oconee performs or supports §54.4(a) intended functions and some switchyard bus does not perform or support §54.4(a) intended functions. Duke has determined that switchyard bus associated with the 525 kV Switchyard and the Oconee Retail substation do not meet the criteria of §54.4(a). An encompassing group of all switchyard bus except bus associated with the (a) 525 kV Switchyard, or (b) Oconee Retail substation is included in the scope of review.

- **Transmission Conductors**

Some transmission conductors at Oconee perform or support §54.4(a) intended functions and some transmission conductors do not perform or support §54.4(a) intended functions. Duke has determined that transmission conductors associated with the 525 kV Switchyard kV Switchyard, the Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines, and the Oconee Retail substation do not meet the criteria of §54.4(a). An encompassing group of all transmission conductors except those associated with the (a) 525 kV Switchyard, (b) Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines, and (c) Oconee Retail substation is included in the scope of review.

- **Uninsulated Ground Conductors**

Uninsulated ground conductors are electrical conductors (e.g., copper cable, copper bar, steel bar) that are uninsulated (bare) and are used to make ground connections for electrical equipment. Uninsulated ground conductors are connected to electrical equipment housings and electrical enclosures as well as metal structural features such as the cable tray system and building structural steel. The ground conductors are always isolated or insulated from the electrical operating circuits.

Uninsulated ground conductors do not perform any functions that meet the criteria of §54.4(a)(1). Uninsulated ground conductors are not relied upon to remain functional during or following any design basis event.

Guidance for the application of the criteria of §54.4(a)(2) is provided in Section III.c.(iii) of the statement of considerations (SOC) accompanying the issuance of 10 CFR 54 and is repeated below.

SOC to 10 CFR Part 54, Section III.c.(iii)

Pre-application rule implementation has indicated that the description of systems, structures, and components subject to review for license renewal could be broadly interpreted and result in an unnecessary expansion of the review. To limit this possibility for the scoping category relating to nonsafety-related systems, structures, and components, the Commission intends this nonsafety-related category (§54.4(a)(2)) to apply to systems, structures, and components whose failure would prevent the accomplishment of an intended function of a safety-related system, structure, and component. An applicant for license renewal should rely on the plant's CLB, actual plant-specific experience, industry-wide operating experience, as appropriate, and existing engineering evaluations to determine those nonsafety-related systems, structures, and components that are the initial focus of the license renewal review. Consideration of hypothetical failures that could result from system interdependencies that are not part of the CLB and that have not been previously experienced is not required.

This SOC guidance is applied to uninsulated ground conductors. No discussion of uninsulated ground conductors is presented in the Oconee UFSAR and no failures of uninsulated ground conductors are identified in the single failure analysis tables in Chapter 8 of the Oconee UFSAR. Failures of uninsulated ground conductors, or other parts of the plant grounding system are not included in the Oconee Probabilistic Risk Assessment (PRA) or the Keowee PRA. A search of failure data at Oconee and the NPRDS and LER databases found no failures of uninsulated ground conductors. Uninsulated ground conductor failures meet the hypothetical failure attributes as discussed in the SOC. Uninsulated ground conductors failures are hypothetical and, per the SOC guidance, are not required to be considered. Therefore, there are no failures of uninsulated ground conductors, which are required to be considered, that could prevent satisfactory accomplishment of any of the functions identified in §54.4(a)(1)(i), (ii), or (iii).

Uninsulated ground conductors are not relied upon in safety analyses or plant evaluation to perform a function that demonstrates compliance with the Commission's regulations for fire protection. Uninsulated ground conductors are not included in the Oconee EQ Program. Uninsulated ground conductors have no relationship to pressurized thermal shock. No credit is taken for uninsulated ground conductors to address anticipated transients without scram or to address station blackout. Therefore, uninsulated ground conductors are not relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental

qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), or station blackout (10 CFR 50.63).

Uninsulated ground conductors do not meet the criteria of §54.4(a).

Column 4 of RAI Response Table 2.6-1 — Application of §54.21(a)(1)(ii) Criteria
Column 4 provides the results when the criteria of §54.21(a)(1)(ii) are applied to the components that meet the criteria of both §54.21(a)(1)(i) and §54.4(a). Application of §54.21(a)(1)(ii) criteria to the applicable components is provided below.

Information provided in this section is intended to also address aspects of RAI 2.6-3, RAI 2.6-4, and RAI 2.6.1-4.

- **Insulators, Isolated-phase Bus, Nonsegregated-phase Bus, Segregated-phase Bus, Switchyard Bus, and Transmission Conductors**

These components are not subject to replacement based on a qualified life or specified time period. Therefore, these components meet the criteria of §54.21(a)(1)(ii).

- **Electrical Penetration Assemblies**

Electrical penetration assemblies are included in the Oconee EQ program and do not meet the criteria of §54.21(a)(1)(ii). The details of this determination are provided in Section 2.6.6.2 of Exhibit A of the Application. Clarifying information is also included in the Response to RAI 2.6-3.

- **Insulated Cables and Connections**

Most insulated cables and connections are not replaced based on a qualified or specified time period. Insulated cables and connections included in the EQ program and used for fire detectors do not meet the criteria of §54.21(a)(1)(ii). The details of these determinations are provided in Section 2.6.6.1 of Exhibit A of the Application. Clarifying information regarding fire detector cables is also included in the Response to RAI 2.6-4. Except for those included in the EQ program or used for fire detectors, all insulated cables and connections meet the criteria of §54.21(a)(1)(i).

Column 5 of RAI Response Table 2.6-1 — Electrical Components subject to an AMR
Column 5 provides the results of the application of the criteria of §54.21(a)(1)(i), §54.4(a), and §54.21(a)(1)(ii) to electrical components, which identifies the electrical components included in the aging management review. Screening and scoping are performed as a progressive process. Since a component must meet all three criteria, the remaining scoping and screening criteria are identified as not applicable (N/A) for a component which is found not to meet one of the previously applied criteria. Electrical component intended functions are identified in Table 2.6-1 of Exhibit A of the Application.

RAI Response Table 2.6-1
Summary of Screening & Scoping Results for Oconee Electrical Components

1	2	3	4	5
Electrical Component	**§54.21(a)(1)(i) Criteria Are Met**	**Application of §54.4(a) Criteria**	**Application of §54.21(a)(1)(ii) Criteria**	**Electrical Components Subject to or Included in the AMR**
Alarm Units	No	N/A	N/A	N/A
Analyzers	No	N/A	N/A	N/A
Annunciators	No	N/A	N/A	N/A
Batteries	No	N/A	N/A	N/A
Chargers	No	N/A	N/A	N/A
Circuit Breakers	No	N/A	N/A	N/A
Converters	No	N/A	N/A	N/A
Communication Equipment	No	N/A	N/A	N/A
Electrical Controls and Panel Internal Component Assemblies	No	N/A	N/A	N/A
Electrical Penetration Assemblies	Yes	Electrical penetration assemblies meet the criteria of §54.4(a).	Electrical penetration assemblies do not meet the criteria of §54.21(a)(1)(ii). *See Section 2.6.6.2 of Exhibit A of the Application.*	N/A
Elements	No	N/A	N/A	N/A
Fuses	No. *See Section 2.6.6.7 of Exhibit A of the Application.*	N/A	N/A	N/A
Generators	No	N/A	N/A	N/A
Heat Tracing	No. *See Section 2.6.6.3 of Exhibit A of the Application.*	N/A	N/A	N/A
Heaters	No. *See Section 2.6.6.3 of Exhibit A of the Application.*	N/A	N/A	N/A
Indicators	No	N/A	N/A	N/A

RAI Response Table 2.6-1
Summary of Screening & Scoping Results for Oconee Electrical Components

1	2	3	4	5
Electrical Component	**§54.21(a)(1)(i) Criteria Are Met**	**Application of §54.4(a) Criteria**	**Application of §54.21(a)(1)(ii) Criteria**	**Electrical Components Subject to or Included in the AMR**
Insulated Cables and Connections	Yes	An encompassing group of all insulated cables and connections except those associated with the (a) 525 kV Switchyard, (b) Radwaste Facility, or (c) Oconee Retail substation is included in the scope of review.	Except for those included in the EQ program or used for fire detectors, all insulated cables and connections meet the criteria of §54.21(a)(1)(i). *See Section 2.6.6.1 of Exhibit A of the Application and the Response to RAI 2.6-4.*	An encompassing group of all insulated cables and connections except those (1) associated with the 525 kV Switchyard, Radwaste Facility, or Oconee Retail substation, (2) included in the EQ program, or (3) used for fire detectors is included in the aging management review.
Insulators	Yes	An encompassing group of all insulators except those associated with the (a) 525 kV Switchyard, (b) Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines, or (c) Oconee Retail substation is included in the scope of review.	Insulators meet the criteria of §54.21(a)(1)(ii).	An encompassing group of all insulators except those associated with the (1) 525 kV Switchyard, (2) Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines, or (3) Oconee Retail substation is included in the aging management review.
Inverters	No	N/A	N/A	N/A
Isolated-Phase Bus	Yes	An encompassing group of all isolated-phase bus is included in the scope of review.	Isolated-phase bus meets the criteria of §54.21(a)(1)(ii).	An encompassing group of all isolated-phase bus is included in the aging management review.
Isolators	No	N/A	N/A	N/A
Light Bulbs	No	N/A	N/A	N/A
Load Centers	No	N/A	N/A	N/A
Loop Controllers	No	N/A	N/A	N/A
Meters	No	N/A	N/A	N/A
Motor Control Centers	No	N/A	N/A	N/A
Motors	No	N/A	N/A	N/A
Nonsegregated-Phase Bus	Yes	An encompassing group of all nonsegregated-phase bus is included in the scope of review.	Nonsegregated-phase bus meets the criteria of §54.21(a)(1)(ii).	An encompassing group of all nonsegregated-phase bus is included in the aging management review.
Power Distribution Panels	No	N/A	N/A	N/A
Power Supplies	No	N/A	N/A	N/A
Radiation Monitors	No	N/A	N/A	N/A

RAI Response Table 2.6-1
Summary of Screening & Scoping Results for Oconee Electrical Components

1	2	3	4	5
Electrical Component	**§54.21(a)(1)(i) Criteria Are Met**	**Application of §54.4(a) Criteria**	**Application of §54.21(a)(1)(ii) Criteria**	**Electrical Components Subject to or Included in the AMR**
Recorders	No	N/A	N/A	N/A
Regulators	No	N/A	N/A	N/A
Relays	No	N/A	N/A	N/A
RTDs	No. *See Section 2.6.6.5 of Exhibit A of the Application and the Response to RAI 2.6-6.*	N/A	N/A	N/A
Segregated-Phase Bus	Yes	Segregated-phase bus meets the criteria of §54.4(a).	Segregated-phase bus meets the criteria of §54.21(a)(1)(ii).	Segregated-phase bus is subject to an aging management review.
Sensors	No	N/A	N/A	N/A
Signal Conditioners	No	N/A	N/A	N/A
Solenoid Operators	No	N/A	N/A	N/A
Solid-State Devices	No	N/A	N/A	N/A
Surge Arresters	No	N/A	N/A	N/A
Switches	No	N/A	N/A	N/A
Switchgear	No	N/A	N/A	N/A
Switchyard Bus	Yes	An encompassing group of all switchyard bus except bus associated with the (a) 525 kV Switchyard, or (b) Oconee Retail substation is included in the scope of review.	Switchyard bus meets the criteria of §54.21(a)(1)(ii).	An encompassing group of all switchyard bus except bus associated with the (1) 525 kV Switchyard, or (2) Oconee Retail substation is included in the aging management review.
Thermocouples	No. *See Section 2.6.6.6 of Exhibit A of the Application and the Response to RAI 2.6-7.*	N/A	N/A	N/A
Transducers	No	N/A	N/A	N/A
Transformers	No. *See Section 2.6.6.4 of Exhibit A of the Application.*	N/A	N/A	N/A

RAI Response Table 2.6-1
Summary of Screening & Scoping Results for Oconee Electrical Components

1	2	3	4	5
Electrical Component	**§54.21(a)(1)(i) Criteria Are Met**	**Application of §54.4(a) Criteria**	**Application of §54.21(a)(1)(ii) Criteria**	**Electrical Components Subject to or Included in the AMR**
Transmission Conductors	Yes	An encompassing group of all transmission conductors except those associated with the (a) 525 kV Switchyard, (b) Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines, or (c) Oconee Retail substation is included in the scope of review.	Transmission conductors meet the criteria of §54.21(a)(1)(ii).	An encompassing group of all transmission conductors except those associated with the (1) 525 kV Switchyard, (2) Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines, or (3) the Oconee Retail substation is included in the aging management review.
Transmitters	No	N/A	N/A	N/A
Uninsulated Ground Conductors	Yes	Uninsulated ground conductors do not meet the criteria of §54.4(a).	N/A	N/A

CHANGES TO EXHIBIT A OF THE APPLICATION

Several sections and tables of Exhibit A of the Application include some reliance on eliminating electrical components from the aging management review based on their installed location. Since this reliance is no longer used in the electrical component scoping process, conforming changes are needed. These changes include specific scoping sections in Chapter 2 of Exhibit A of the Application as well as Chapter 3 of Exhibit A of the Application. RAI Response Table 2.6-2 provides a listing of all sections and tables of Exhibit A of the Application related to electrical components along with information on changes to them. No figures required any changes and are not listed in RAI Response Table 2.6-2. Sections and tables of Exhibit A of the Application have no changes, are superseded, or are eliminated due this change.

RAI Response Table 2.6-2
Summary of Changes to Exhibit A of the Application
Due to the Change in the Electrical Component Scoping Process

Section or Table in Exhibit A of the Application	Title of Section or Table	Changes Made
Section 2.6	Electrical Components	No change
Section 2.6.1	Description of the Process to Identify Electrical Components Subject to an Aging Management Review	Superseded
Section 2.6.2	Bus	No change
Section 2.6.2.1	Phase Bus	No change
Section 2.6.2.1.1	Isolated-Phase Bus	Superseded
Section 2.6.2.1.2	Nonsegregated-Phase Bus	Superseded
Section 2.6.2.1.3	Segregated-Phase Bus	No change
Section 2.6.2.2	Switchyard Bus	Superseded
Section 2.6.3	Insulated Cables and Connections	No change
Section 2.6.4	Insulators	Superseded
Section 2.6.5	Transmission Conductors	Superseded
Section 2.6.6	Electrical Components Not Subject to Aging Management Review	No change to this section or its subsections
Section 2.6.7	Structures and Areas Containing Electrical Components Subject to an Aging Management Review	Superseded
Section 2.6.8	References for Section 2.6	No change
Table 2.6-1	Electrical Component Types Subject to an Aging Management Review and Their Intended Functions	No change
Table 2.6-2	Isolated-Phase Bus Subject to Aging Management Review	Superseded
Table 2.6-3	Nonsegregated-Phase Bus Subject to Aging Management Review	Superseded
Table 2.6-4	Segregated-Phase Bus Subject to Aging Management Review	No change
Table 2.6-5	Switchyard Bus Included in the Aging Management Review	Superseded
Table 2.6-6	Insulated Cables and Connections Subject to Aging Management Review	No change
Table 2.6-7	Insulators Included in the Aging Management Review	Superseded
Table 2.6-8	Transmission Conductors Included in the Aging Management Review	Superseded
Table 2.6-9	Structures and Areas Identified for the Electrical Component Integrated Plant Assessment	Superseded
Section 3.	Identification of Applicable Aging Effects	No change
Section 3.1	Introduction	No change
Section 3.2	Description of the Process to Identify Applicable Aging Effects	No change
Section 3.2.1	Process Overview	No change
Section 3.2.2	Service Environments	Superseded
Section 3.2.2.1	Thermal Environments	No change
Section 3.2.2.2	Radiation Environments	No change
Section 3.2.2.3	Moisture	No change

RAI Response Table 2.6-2
Summary of Changes to Exhibit A of the Application
Due to the Change in the Electrical Component Scoping Process

Section or Table in Exhibit A of the Application	Title of Section or Table	Changes Made
Table 3.2-1	Oconee Thermal Environments	Superseded
Table 3.2-2	Oconee Radiation Environments	Superseded
Section 3.6	Aging Effects for Electrical Components	No change
Section 3.6.1	Description of the Process to Identify Applicable Aging Effects for Electrical Components	No change
Section 3.6.2	Bus	No change
Section 3.6.2.1	Phase Bus	No change to this section or its subsections
Section 3.6.2.2	Switchyard Bus	No change
Section 3.6.2.2.1	Applicable Aging Effects For Switchyard Bus	Superseded
Section 3.6.2.2.2	Industry Experience	No change
Section 3.6.2.2.3	Oconee Operating Experience	No change
Section 3.6.2.2.4	Conclusion	No change
Section 3.6.3	Insulated Cables and Connections	No change
Section 3.6.3.1	Applicable Aging Effects for Insulated Cables and Connections	No change
Section 3.6.3.1.1	Low-Voltage Connector — Moisture	No change
Section 3.6.3.1.2	Medium-Voltage Cable — Moisture	Superseded
Section 3.6.3.1.2.1	Power Cable Installed in Cable Trenches	Eliminated
Section 3.6.3.1.2.2	Power Cables Exposed To Outside Ambient Conditions	Eliminated
Section 3.6.3.1.2.3	Direct Buried Power Cables	Eliminated
Section 3.6.3.1.2.4	Power Cables Run In Conduit	Eliminated
Section 3.6.3.1.3	Low & Medium Voltage Cable — Radiation	No change
Section 3.6.3.1.4	Low & Medium Voltage Cable — Heat	No change
Section 3.6.3.2	Industry Experience	No change
Section 3.6.3.3	Oconee Operating Experience	No change
Section 3.6.3.4	Conclusion	No change
Section 3.6.4	Insulators	No change to this section or its subsections
Section 3.6.5	Transmission Conductors	No change to this section or its subsections
Section 3.6.6	References for Section 3.6	No change
Table 3.6-1	Applicable Aging Effects for Electrical Components	No change
Table 3.6-2	Self-Heating Temperature Rise for Insulated Cables & Connections	No change
Table 3.6-3	Service Conditions for Insulated Cables and Connections	Superseded
Table 3.6-4	Medium Voltage Insulated Cables Exposed to Moisture	Eliminated
Table 3.6-5	Radiation Dose Data for Insulated Cables and Connection Materials	No change
Table 3.6-6	Temperature Data for Insulated Cables and Connection Materials	No change

Note: Replacement sections and tables are provided below.

Replacement Section 2.6.1 of Exhibit A of the Application
Description of the Process to Identify Electrical Components Subject to Aging Management Review

The initial step to identify electrical components to be included in the aging management review is to determine those electrical components that perform their intended function without moving parts or without a change in configuration or properties. NEI 95-10 Rev. 0, Appendix B [Reference 2.6-1 of Exhibit A of the Application, Table B-1], §54.21(a)(1)(i) [Reference 2.6-2 of Exhibit A of the Application]. Various Oconee electrical drawings are reviewed to identify electrical components. Subsequent stages of the identification process consider (1) whether or not the electrical component is within the scope of license renewal and (2) whether or not the electrical component is subject to replacement based on a qualified life or specified time period. Based on this review, Duke has determined that the Oconee electrical component types that perform their intended function without moving parts or without a change in configuration or properties, and are included in the aging management review, are as follows:

- Bus
- Insulated Cables & Connections
- Insulators
- Transmission Conductors

These electrical components along with their intended functions are listed in Table 2.6-1 of Exhibit A of the Application.

Electrical components interface with other types of components at Oconee and the assessments of these interfacing components are provided in other sections of Exhibit A of the Application. For example, the assessment of electrical racks, panels, frames, cabinets, cable tray, conduit and their supports is provided as part of the Structures and Structural Components review in Sections 2.7 and 3.7 of Exhibit A of the Application.

Sections 2.6.2.1, 2.6.2.3, and 2.6.3 of Exhibit A of the Application along with Replacement Sections 2.6.2.1.1, 2.6.2.1.2, 2.6.2.2, and 2.6.5 of Exhibit A of the Application provide descriptions of the electrical components that are included in the aging management review. Section 2.6.6 of Exhibit A of the Application provides a basis for the determination that several electrical components are not subject to aging management review. Replacement Section 2.6.7 of Exhibit A of the Application identifies the structures and areas containing electrical components included in the aging management review.

Replacement Section 2.6.2.1.1 of Exhibit A of the Application
Isolated-Phase Bus
An isolated-phase bus is an electrical bus in which each phase conductor is enclosed by an individual metal housing and separated from adjacent conductor housings by an air space. Isolated-phase bus structural supports are reviewed in Sections 2.7 and 3.7 of Exhibit A of the Application.

Isolated-phase bus is used at both Keowee and Oconee. Keowee isolated-phase bus is used to connect the main switchgear of each unit to the Keowee main step-up transformer. Oconee isolated-phase bus is used to connect each unit generator to its main step-up transformer and unit auxiliary transformer. Keowee isolated-phase bus is designated as QA Condition 1 and meets the criteria of §54.4(a). Oconee isolated-phase bus is not designated as QA Condition 1, but is included in the scope of review as part of an encompassing group. Therefore, an encompassing group of all isolated-phase bus is included in the aging management review.

The list of isolated-phase bus included in the aging management review is provided in Replacement Table 2.6-2 of Exhibit A of the Application. A typical cross-section of the isolated-phase bus is shown in Figure 2.6-1 of Exhibit A of the Application.

Replacement Section 2.6.2.1.2 of Exhibit A of the Application
Nonsegregated-Phase Bus
Nonsegregated-phase bus is an electrical bus constructed with all phase conductors in a common metal enclosure with only air space as a barrier between the phases. Nonsegregated-phase bus structural supports are reviewed in Sections 2.7 and 3.7 of Exhibit A of the Application.

Nonsegregated-phase bus is used in the Oconee 4160V and 6900V power systems. Oconee 4160V nonsegregated-phase bus is used to connect QA Condition 1 switchgear and meets the criteria of §54.4(a). Oconee 6900V nonsegregated-phase bus is used to connect the unit auxiliary and start-up transformers to the reactor coolant pump switchgear and is included in the scope of review as part of an encompassing group. Therefore, an encompassing group of all nonsegregated-phase bus is included in the scope of review.

The list of nonsegregated-phase buses included in the aging management review is provided in Replacement Table 2.6-3 of Exhibit A of the Application. A typical cross-section of a nonsegregated-phase bus is shown in Figure 2.6-2 of Exhibit A of the Application.

Replacement Section 2.6.2.2 of Exhibit A of the Application
Switchyard Bus
Switchyard bus is uninsulated, unenclosed, rigid electrical conductor used in switchyards and switching stations to provide an electrically common connection point for disconnect switches and flexible connections. Insulators support switchyard bus. The review of switchyard bus includes the switchyard bus and the hardware used to secure the bus to an insulator. Since the connections to disconnect switches are maintained as part of the switch, switchyard bus connections to disconnect switches are considered a part of the disconnect switch. Flexible conductors are reviewed as transmission conductors in Replacement Section 2.6.5 and Section 3.6.5 of Exhibit A of the Application. Insulators are reviewed in Replacement Section 2.6.4 and Section 3.6.4 of Exhibit A of the Application.

An encompassing group of all switchyard bus except bus associated with the (a) 525 kV Switchyard, or (b) Oconee Retail substation is included in the aging management review. This encompassing group includes all switchyard bus subject to an aging management review (i.e., meets the criteria of §54.21(a)(1)(i), §54.4(a), and §54.21(a)(1)(ii)) and includes switchyard bus that may not meet these criteria.

The list of switchyard bus included in the aging management review is provided in Replacement Table 2.6-5 of Exhibit A of the Application. Figure 2.6-4 of Exhibit A of the Application is a one-line diagram showing the 230 kV Switchyard layout.

Replacement Section 2.6.4 of Exhibit A of the Application
Insulators
An insulator is an insulating material in a form designed to (a) support a conductor physically and (b) separate the conductor electrically from another conductor and object. The insulators evaluated in the electrical component integrated plant assessment are station post, strain, and suspension insulators used to support uninsulated, high voltage electrical conductors such as switchyard bus and transmission conductors. Insulators are supported by structural steel components. Insulators evaluated in this section are those that are separate components and not a part of a larger component. Structural steel supports and connecting hardware are reviewed in Sections 2.7 and 3.7 of Exhibit A of the Application. Transmission conductors and connecting hardware are reviewed in Replacement Section 2.6.5 and Section 3.6.5 of Exhibit A of the Application, and switchyard bus and connecting hardware are reviewed in Replacement Section 2.6.2.2 and Section 3.6.2.2 of Exhibit A of the Application.

An encompassing group of all insulators except those associated with the (a) 525 kV Switchyard, (b) Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines, or (c) Oconee Retail substation is included in the aging management review. This encompassing

group includes all insulators subject to an aging management review (i.e., meets the criteria of §54.21(a)(1)(i), §54.4(a), and §54.21(a)(1)(ii)) and includes insulators that may not meet these criteria.

The list of insulators included in the aging management review is provided in Replacement Table 2.6-7 of Exhibit A of the Application. Figure 2.6-6 of Exhibit A of the Application is a cross-section drawing of a typical strain or suspension insulator and a cross-section of a typical post insulator is shown in Figure 2.6-7 of Exhibit A of the Application.

Replacement Section 2.6.5 of Exhibit A of the Application
Transmission Conductors
Transmission conductors are uninsulated, stranded wire conductors and are used outside buildings in high voltage applications. Insulators support transmission conductors. Transmission conductors are terminated at other high voltage electrical components such as transformers, circuit breakers, and disconnect switches. The review of transmission conductors includes the transmission conductors, transmission conductor connections to switchyard bus and other transmission conductors, and the hardware used to secure transmission conductors to insulators. Insulators are reviewed in Replacement Section 2.6.4 and Section 3.6.4 of Exhibit A of the Application. Switchyard bus is reviewed in Replacement Section 2.6.2.2 and Section 3.6.2.2 of Exhibit A of the Application.

An encompassing group of all transmission conductors except for transmission conductors associated with the (a) 525 kV Switchyard, (b) Jocassee, Calhoun, Oconee, and Dacus 230 kV transmission lines, or (c) Oconee Retail substation is included in the aging management review. This encompassing group includes all transmission conductors subject to an aging management review (i.e., meets the criteria of §54.21(a)(1)(i), §54.4(a), and §54.21(a)(1)(ii)) and includes transmission conductors that may not meet these criteria.

Transmission conductors included in the aging management review are listed in Replacement Table 2.6-8 of Exhibit A of the Application.

Replacement Section 2.6.7 of Exhibit A of the Application
Structures and Areas Containing Electrical Components Included in the Aging Management Review
Structures and areas are identified for the electrical component integrated plant assessment so that relevant environmental data can be obtained. The applicable environments of these identified structures and areas are included in the aging assessment of electrical components to determine the applicability of the identified potential aging effects. The structures and areas containing the electrical components included in the aging management review are listed in Replacement Table 2.6-9 of Exhibit A of the Application.

Replacement Table 2.6-2 of Exhibit A of the Application
Isolated-Phase Bus Included in the Aging Management Review

Description	Installed Locations
All sections of Keowee Unit 1 Isolated-Phase Bus	Keowee Structures Keowee Transformer Yard
All sections of Keowee Unit 2 Isolated-Phase Bus	Keowee Structures Keowee Transformer Yard
All sections of Oconee Unit 1 Isolated-Phase Bus	Turbine Building Oconee Transformer Yard
All sections of Oconee Unit 2 Isolated-Phase Bus	Turbine Building Oconee Transformer Yard
All sections of Oconee Unit 3 Isolated-Phase Bus	Turbine Building Oconee Transformer Yard

Replacement Table 2.6-3 of Exhibit A of the Application
Nonsegregated-Phase Bus Included in the Aging Management Review

Description	Installed Locations
All sections of Oconee Unit 1 4160V Nonsegregated-Phase Bus	Turbine Building Unit 1&2 Switchgear Blockhouse Oconee Transformer Yard
All sections of Oconee Unit 2 4160V Nonsegregated-Phase Bus	Turbine Building Unit 1&2 Switchgear Blockhouse Oconee Transformer Yard
All sections of Oconee Unit 3 4160V Nonsegregated-Phase Bus	Turbine Building Unit 3 Switchgear Blockhouse Oconee Transformer Yard
All sections of Oconee Unit 1 6900V Nonsegregated-Phase Bus	Turbine Building Unit 1&2 Switchgear Blockhouse Oconee Transformer Yard
All sections of Oconee Unit 2 6900V Nonsegregated-Phase Bus	Turbine Building Unit 1&2 Switchgear Blockhouse Oconee Transformer Yard
All sections of Oconee Unit 3 6900V Nonsegregated-Phase Bus	Oconee Transformer Yard

Replacement Table 2.6-5 of Exhibit A of the Application
Switchyard Bus Included in the Aging Management Review

Description
All switchyard bus in the 230 kV Switchyard
All switchyard bus in the 100kV Switching Station

Replacement Table 2.6-7 of Exhibit A of the Application
Insulators Included in the Aging Management Review

Description
Insulators supporting bus and conductors in the 230 kV Switchyard
Insulators supporting conductors in the Keowee Transformer Yard
Insulators supporting 230 kV conductors in the Oconee Transformer Yard
Insulators supporting the Keowee Transmission Line
Insulators supporting the 100 kV Fant Black Line
Insulators supporting bus and conductors in the 100 kV Switching Station

Replacement Table 2.6-8 of Exhibit A of the Application
Transmission Conductors Included in the Aging Management Review

Description
Transmission conductors in the 230 kV Switchyard
Transmission conductors in the Keowee Transformer Yard
230 kV transmission conductors in the Oconee Transformer Yard
Transmission conductors in the Keowee Transmission Line
Transmission conductors in the 100 kV Fant Black Line
Transmission conductors in the 100 kV Switching Station

Replacement Table 2.6-9 of Exhibit A of the Application Structures and Areas Containing Electrical Components Included in the Aging Management Review

Structure or Area	Description
Auxiliary Buildings	Includes all levels of all 3 unit Auxiliary Buildings including the Hot Machine Shop and Spent Fuel Pools for Units 1&2 (shared) and Unit 3, and Penetration Rooms
Intake Structure	Includes the CCW pump Intake Structure
Keowee Structures	Includes the Breaker Vault, Intake Structure, Penstock, Powerhouse, Service Bay Structure, and Spillway
Reactor Buildings	Includes all levels of all three Reactor Buildings and the Unit Vents
Standby Shutdown Facility	Includes all levels and rooms in the Standby Shutdown Facility
Turbine Buildings	Includes all levels of all 3 unit Turbine Buildings and the Switchgear Blockhouses for Units 1&2 (shared) and Unit 3
Yard Structures	Includes all areas and components outside the other buildings. Specifically, this includes the following: • **230 kV Keowee Transmission Line Towers** • **230 kV Switchyard Structures and Relay House** (includes the area within the switchyard boundary fence) • **Appendix R Warehouse** [Appendix R cable only] • **Cable Conduit** • **Cable Trenches** • **Direct Buried Cables** • **Elevated Water Storage Tank** • **Keowee Transformer Yard** [for components associated with Keowee Transformer 1] (includes the gravel covered area outside, on the South side of the Keowee Powerhouse structure where Keowee Transformer 1 and Keowee transmission line support structures are located) • **Oconee Transformer Yard** [for components associated with Transformers CT1, CT2, and CT3] (includes the gravel covered area outside, on the East side of the Turbine Buildings where the unit main step-up transformers and the unit start-up transformers are located)
All remaining site structures and areas	Includes all remaining structures and areas not identified earlier in this table. The structures and areas described earlier in this table include all Oconee Class 1 and 2 structures in addition to some Class 3 structures. The remaining structures identified by this category are all Class 3 structures including the 100 kV Switching Station and the 100 kV Fant Black transmission line. See Section 2.7 of Exhibit A of the Application for additional information on Class 1, 2, and 3 structures.

Replacement Section 3.2.2 of Exhibit A of the Application
Service Environments
The service environment, in which components are installed, along with other factors, establishes the applicable aging effects of concern for license renewal. This subsection identifies the service environments for all areas that contain structures and components that are included in the aging management review. The service environments identified in this section are thermal, radiation, and moisture. These environments are described in Sections 3.2.2.1 through 3.2.2.3 of Exhibit A of the Application.

Replacement Table 3.2-1 of Exhibit A of the Application
Oconee Thermal Environments

Structure or Area	Specific Area Description and Comments	Bounding Temperature
Auxiliary Buildings	Main Steam Penetration Concrete (Penetration Rooms)	150°F (65.6°C)
	Areas Cooled by the Auxiliary Building Ventilation System	104°F (40.0°C)
	Spent Fuel Pool Areas	104°F (40.0°C)
	Equipment Rooms (designed for 86°F)	90°F (32.2°C)
	Control Rooms, Cable Rooms (designed for 74°F)	85°F (29.4°C)
	Control Battery Rooms	80°F (26.7°C)
	Areas Cooled by the Auxiliary Building Air Conditioning System	75°F (23.9°C)
Intake Structure	Areas Exposed to Site Ambient	105°F (40.6°C)
Keowee Structures	All Areas	105°F (40.6°C)
Reactor Buildings	Vessel Head and Area Around the Control Rod Drives (maintained near 150°F)	175°F (79.4°C)
	High Elevations in Steam Generator Cavities	132°F (55.6°C)
	Elevation Around Top of Reactor Coolant Pumps	126°F (52.2°C)
	Elevation 797+6	116°F (46.7°C)
Standby Shutdown Facility	Diesel Generator, Switchgear, Pump, HVAC Equipment Rooms	104°F (40.0°C)
	Control, Computer, Battery, Response (CAS) Rooms	72°F (22.2°C)
Turbine Buildings	General Areas	105°F (40.6°C)
Yard Structures	Areas Exposed to Site Ambient	105°F (40.6°C)
	Appendix R Warehouse	105°F (40.6°C)
	Cable Trenches and Direct Buried	80°F (26.7°C)
All remaining site structures and areas	All areas as defined in Replacement Table 2.6-9 of Exhibit A of the Application	105°F (40.6°C)

Replacement Table 3.2-2 of Exhibit A of the Application
Oconee Radiation Environments

Structure	Area	Maximum 40-Year Normal Operating Dose (rads)	Maximum 60-Year Normal Operating Dose (rads)
Reactor Buildings	Reactor Cavity Steam Generator Cavity Elev. 797+6 - zone 1 Elev. 825+0 - zone 1 Elev. 844+6 - zone 1	3×10^7	4.5×10^7
	Elev. 777+6 - zone 1	1×10^7	1.5×10^7
Auxiliary Buildings	Elev. 758+0 - zones 5-7 Elev. 771+0 - zones 1-8 Elev. 783+9 - zones 1-6 Elev. 796+6 - zones 1-2 Elev. 809+3 - zone 2 Elev. 822+0 - zones 2-3 Penetration Rooms	1×10^6	1.5×10^6
Reactor Buildings	Elev. 777+6 - zone 2	3×10^5	4.5×10^5
Auxiliary Buildings	Elev. 758+0 - zones 1-4 Elev. 796+6 - zones 3-4	1×10^5	1.5×10^5
Reactor Buildings	Elev. 777+6 - zone 3 Elev. 797+6 - zone 2 Elev. 825+0 - zone 2 Elev. 844+6 - zone 2 General Areas	3×10^4	4.5×10^4
Auxiliary Buildings	Elev. 809+3 - zone 3 Elev. 822+0 - zone 1	1×10^4	1.5×10^4
	Elev. 771+0 - zones 9-10 Elev. 783+9 -zones 7, 8a-8d Elev. 796+6 - zones 5-6 Elev. 809+3 - zone 1	1×10^3	1.5×10^3
Turbine Buildings	All Areas	Less than 1×10^3	Less than 1.5×10^3
Auxiliary Buildings	Elev. 838+0 - zones 1a-e, 2	1×10^2	1.5×10^2
	Cable Spreading Rooms Control Rooms Electrical Equipment Rooms	Less than 1×10^2	Less than 1.5×10^2

Structure	Area	Maximum 40-Year Normal Operating Dose (rads)	Maximum 60-Year Normal Operating Dose (rads)
Intake Structure Keowee Structures Standby Shutdown Facility Yard Structures All remaining site structures and areas (as defined in Replacement Table 2.6-9 of Exhibit A of the Application)	All Areas	Negligible	Negligible

Replacement Section 3.6.2.2.1 of Exhibit A of the Application
Applicable Aging Effects For Switchyard Bus
Switchyard bus is exposed to ambient environmental conditions for Yard Structures as described in Section 3.2 of Exhibit A of the Application. These environmental conditions include temperatures up to 105°F (40.6°C), negligible radiation, and exposure to moisture from all forms of precipitation. Self-heating contributes an increase in temperature of the bus of up to 30°C.

The only material used for switchyard bus is aluminum. All bus connections within the review boundaries are welded connections. For the ambient environmental conditions at Oconee, no aging effects are identified that could cause a loss of intended function during the extended period of operation.

Replacement Section 3.6.3.1.2 of Exhibit A of the Application
Medium-Voltage Cable — Moisture
Section 3.7.4 of the DOE Cable AMG [Reference 3.6-1 of Exhibit A of the Application] describes a survey of 25 fossil and nuclear power plants which was conducted to determine the number and types of medium-voltage cable failures that have occurred. The survey identified only 27 failures in almost 1000 plant years of experience. The bulk of the failures that did occur are primarily related to wetting in conjunction with manufacturing defects or damaged terminations due to improper installation, which are not aging effects subject to aging management review.

The effects of moisture-produced water trees on medium-voltage cable are examined in Section 4.1.2.5 of the DOE Cable AMG. Water trees occur when the insulating materials are exposed to long-term, continuous voltage stress and moisture; these trees eventually result in breakdown of the dielectric and ultimate failure. The growth and propagation of water trees is somewhat unpredictable, and few occurrences are noted for cables operated below 15kV. Water treeing is a degradation and long-term failure phenomenon that is

documented for medium-voltage electrical cable with XLPE or high molecular weight polyethylene (HMWPE) insulation.

As shown on Table 2.6-6 of Exhibit A of the Application, Oconee does not use XLPE or HMWPE insulated cables in medium-voltage (2kV to 15kV) applications. Therefore, aging effects related to cable exposed to moisture are not applicable for Oconee insulated cables and connections.

Sections 3.6.3.1.2.1 through 3.6.3.1.2.4 of Exhibit A of the Application
Note: *Sections 3.6.3.1.2.1 through 3.6.3.1.2.4 of Exhibit A of the Application, "Power Cable Installed in Cable Trenches," "Power Cables Exposed To Outside Ambient Conditions," "Direct Buried Power Cables." and "Power Cables Run In Conduit" are eliminated by the determination in Replacement Section 3.6.3.1.2 that aging effects related to insulated cable exposed to moisture are not applicable.*

Replacement Table 3.6-3 of Exhibit A of the Application
Service Conditions for Insulated Cables and Connections

Stressor	Structure or Area Containing Insulated Cables and Connections	Specific Area or Insulation Material	Bounding Value
Moisture	Intake Structure	Areas exposed to outside ambient conditions	Precipitation
	Keowee Structures	Turbine shaft wells	Wall water seepage
	Yard Structures	Areas exposed to outside ambient conditions	Precipitation
		Cable trench	trench floor standing water
		Direct buried	surface water drainage, soil moisture
		Conduit	water collection
	All remaining site structures and areas (as defined in Replacement Table 2.6-9 of Exhibit A of the Application)	Areas exposed to outside ambient conditions	Precipitation
Radiation	Reactor Buildings	EP, EPR, EPDM, FR-EPR, XLP, XLPE, Vulkene, FR-XLPE	4.5×10^7 rads
	Auxiliary Buildings	All materials	1.5×10^6 rads
	Turbine Buildings	All materials	less than 1.5×10^3 rads
	Intake Structure Keowee Structures Standby Shutdown Facility Yard Structures All remaining site structures and areas (as defined in Replacement Table 2.6-9 of Exhibit A of the Application)	All materials	Negligible
Temperature	Reactor Buildings	EP, EPR, EPDM, FR-EPR, XLP, XLPE, Vulkene, FR-XLPE	153.4°F (67.4°C)
	Auxiliary Buildings Intake Structure Keowee Structures Standby Shutdown Facility Turbine Buildings Yard Structures All remaining site structures and areas (as defined in	EP, EPR, EPDM, FR-EPR Hypalon Kapton Kerite-HTK Phenolic SR XLP, XLPE, Vulkene, FR-XLPE	158.45°F (70.25°C)
		Butyl PE	123.1°F (50.6°C)

Stressor	Structure or Area Containing Insulated Cables and Connections	Specific Area or Insulation Material	Bounding Value
	Replacement Table 2.6-9 of Exhibit A of the Application)	AVA Fiberglass Nylon Polyalkene PVC	105°F (40.6°C)

Table 3.6-4 of Exhibit A of the Application

Note: *Table 3.6-4 of Exhibit A of the Application, "Medium-Voltage Insulated Cables Exposed to Moisture," was eliminated by the determination in Replacement Section 3.6.3.1.2 above that aging effects related to insulated cable exposed to moisture are not applicable.*

Note: *This concludes the replacement sections and tables.*

RAI 2.6-2 (11/25/98A)
The scoping of systems, structures, and components required by the license renewal rule and the maintenance rule are similar. Provide a comparison of the scope of electrical systems and components for these rules and describe the significant differences, if any.

Response to RAI 2.6-2
The staff is correct in that the maintenance rule scoping (§50.65) is similar to license renewal rule scoping (§54.4), but there are distinct differences. Electrical "systems" are not scoped as part of the Oconee integrated plant assessment. As such, it is not practical to perform a comparison of the scope of maintenance rule electrical systems to those within the scope of license renewal and no comparison is provided. A description of electrical component scoping is provided in the Response to RAI 2.6-1 with summary results provided in RAI Response Table 2.6-1.

RAI 2.6-3 (11/25/98A)
Section 2.6.1 of the application identified electrical buses, insulated cables and connections, insulators, and transmission conductors as the electrical components that are subject to an aging management review. 10 CFR 54.21(a)(1)(i) lists electrical and mechanical penetrations as components that are subject to an aging management review. Identify any non-EQ electrical penetration assemblies that are subject to an aging management review and describe their intended functions.

Response to RAI 2.6-3
Although not specifically stated in Exhibit A of the Application, *all* electrical penetration assemblies at Oconee are included in the environmental qualification (EQ) program. The staff is correct in stating that electrical penetration assemblies are subject to an aging management review based on the criteria of §54.21(a)(1)(i). However, as explained in Section 2.6.6.2 of Exhibit A of the Application, electrical penetration assemblies are excluded from an aging management review based on the qualified life criteria of §54.21(a)(1)(ii).

Electrical penetration assemblies are addressed in Section 5.6 of Exhibit A of the Application. Information regarding the Oconee EQ program is provided in the Response to RAIs 5.6-1, 5.6-2, and 5.6-3 which are provided as Attachment 3 to Duke letter to the NRC dated February 8, 1999.

RAI 2.6-4 (11/25/98A)
Section 2.6.6.1.2 of the application identified insulated cables and connections used for fire detectors as part of the fire detection system and excluded them from an aging management review on the grounds that they are replaced based on a performance or condition program. The Commission has concluded in the statements of consideration for 10 CFR Part 54, Section III.d.(vi) that fire protection components that perform active functions can be generally excluded from an aging management review on the basis of performance or condition-monitoring programs.

Since electrical cables and connectors are identified in 10 CFR 54.21 as being subject to an aging management review because they perform their intended function without moving parts or without a change in configuration or properties, describe how the fire detector insulated cables are different from other electrical cables.

Response to RAI 2.6-4
The staff is correct that electrical cables and connections are subject to an aging management review based on the criteria of §54.21(a)(1)(i). Fire detector insulated cables are not physically different than other insulated cables.

Duke did not use the Commission's guidance provided in Section III.d.(vi) of the statement of considerations (SOC) for 10 CFR 54. As explained in Section 2.6.6.1.2 of Exhibit A of the Application, fire detector cables are excluded from an aging management review based on the criteria of §54.21(a)(1)(ii) along with information provided in SOC Section III.f.(i)(b). This section of the SOC pertains directly to the "long-lived" structures and components criteria of the integrated plant assessment.

Replacement based on performance or condition is discussed in the SOC Section III.f.(i)(b). As stated in the SOC, the Commission does not intend to preclude a license renewal applicant from providing site-specific justification in a license renewal application that replacement on the basis of performance or condition for a passive component provides reasonable assurance that the intended function of the passive component will be maintained in the period of extended operation. The SOC further states that the Commission would generally expect that replacement based on performance or condition would have defined performance or condition measuring methods, an established monitoring frequency that supports timely discovery of degraded conditions, and an appropriate replacement criterion. Fire detector insulated cables meet these criteria — the details of which are provided in Section 2.6.6.1.2 of Exhibit A of the Application.

See also the Response to RAI 2.2-4 and the Response to RAI 2.6-1 for information related to fire detector cables.

RAI 2.6-5 (11/25/98A)
For cables that are stored onsite for the purpose of rewiring plant equipment following a design basic event in order to meet the 72-hour cold shutdown requirement, discuss the stressors these cables are exposed to, the resulting aging effects, and the need for aging management review.

Response to RAI 2.6-5
The only cables subject to an aging management review which are stored onsite (i.e., not installed) are the Appendix R cables. Therefore, this response assumes that the 72-hour cold shutdown requirement the staff is referring to in this RAI is fire protection/Appendix R.

The 10 CFR 50 Appendix R insulated cables are stored on a reel in the Appendix R warehouse. The Appendix R warehouse is located in an area where exposure to plant radiation is negligible and the warehouse provides protection from moisture and sunlight. Therefore, radiation and moisture are not applicable stressors for the Appendix R insulated cables. Temperature is the only applicable stressor. The Appendix R insulated cables are not connected in a circuit so self-heating temperature rise is not applicable for an aging effects review. Replacement Table 3.2-1 of Exhibit A of the Application indicates that the bounding (highest) warehouse temperature is 105°F (40.6°C). Table 3.6-6 of Exhibit A of the Application identifies the maximum temperature for a 60-year life along with the 60-year life endpoint for all Oconee cable insulation materials, which includes the Appendix R cable insulation materials. PVC insulation has the lowest 60-year life temperature of 111.9°F (44.4°C). The Appendix R warehouse bounding temperature is less than the maximum 60-year life temperature for all insulation materials identified in Table 3.6-6 which indicates that margin exists that extends the life of the Appendix R cable beyond 60 years.

This temperature margin provides assurance that aging of the Appendix R insulated cables is not progressing at a rate that will lead to loss of the cable intended function in the extended period of operation and no aging management is required.

NOTE: RAIs 2.6-6 and 2.6-7 are similar so they are being answered together.

RAI 2.6-6 (11/25/98A)
Section 2.6.6.5 of the application concludes that resistance temperature detectors (RTDs) do not perform their function without moving parts or without a change in configuration or properties and thus not subject to an aging management review. The industry guidance for license renewal in NEI 95-10, Revision 0, Appendix B, recommends that RTDs should be subject to an aging management review.

Provide an aging management review for the RTDs, or provide a more detailed basis for their exclusion.

RAI 2.6-7 (11/25/98A)
Section 2.6.6.6 of the application concludes that thermocouples do not perform their function without moving parts or without a change in configuration or properties. The industry guidance for license renewal in NEI 95-10, Revision 0, Appendix B recommends that thermocouples should be subject to an aging management review.

Provide an aging management review for the thermocouples or provide a more detailed basis for their exclusion.

Response to RAIs 2.6-6 and 2.6-7
RAIs 2.6-6 and 2.6-7 were clarified with the NRC staff during a telephone conference on January 7, 1999. This telephone conference clarified an inconsistency within NEI 95-10 Rev. 0 Appendix B concerning Thermocouples, RTDs, and Temperature Sensors. This clarification is explained below.

Temperature sensors are identified in NEI 95-10 Rev. 0 Appendix B (Item #93) as "Yes (PB only)" which means that the only "passive" intended function of a temperature sensor is that of a mechanical system pressure boundary. Thermocouples and RTDs are essentially types of temperature sensors. Thermocouples and RTDs are identified in NEI 95-10 Rev. 0 Appendix B (Item #121) as "Yes." The consensus reached during the staff conference is that "(PB only)" should be added to the "passive" identification for thermocouples and RTDs and that the electrical intended functions of thermocouples and RTDs are "active" and do not meet the criteria of §54.21(a)(1)(i). Duke understands that this resolves RAI 2.6-6 and RAI 2.6-7.

Duke will request that this change be incorporated into the next revision to NEI 95-10.

RAI 2.6-8 (11/25/98A)
Section 2.6.7 of the application states that the electrical component integrated plant assessment is a component-based review where component characteristics are compared to their service conditions.

Describe the methodology for determining the service conditions, including measured parameters and operational experience, that the components are exposed to and the criteria that are used to determine whether a component is subject to an aging management review based on its location.

Response to RAI 2.6-8
Service conditions reviewed for electrical components included in the integrated plant assessment are temperature, radiation, and moisture.

A summary of the thermal environments are presented in Replacement Table 3.2-1 of Exhibit A of the Application, whose values are obtained from the Oconee UFSAR, design basis documents, temperature measurements, or are conservatively assumed values.

Thermal data obtained from the UFSAR is the maximum recorded site temperature which is used for all components exposed to site ambient conditions. Thermal environmental data from design basis documents are specific area design temperatures. Temperature measurements were taken in the Turbine Building and Reactor Building, which reflect temperatures through all seasons. Temperatures for periods when the unit being monitored was shut down were not included. Measurements in the Turbine Building are averaged. Temperatures for the Reactor Building are conservative 99.73% confidence mean values (i.e., 99.73% of the time the actual temperature in the area is at or below the cited temperature).

Temperatures are assumed for Keowee, the Appendix R Warehouse, cable trenches, direct buried, and buried conduit and all remaining site structures and areas. Since no steam pipes or other such heat-generating equipment is inside Keowee, the structures normally remain comfortable, even on hot summer days. Using the recorded site maximum temperature of 105°F (40.6°C) from the UFSAR as the bounding temperature is conservative since the average temperature (due to daily and seasonal variations) is less. The Appendix R Warehouse has no cooling equipment installed but does have roof vents for ventilation. The recorded site maximum temperature of 105°F (40.6°C) from the UFSAR is used for the warehouse and is considered conservative because of the daily and seasonal variations in site ambient temperature. The temperature for cable trench, direct buried, and buried conduit environments is conservatively assumed to be 80°F (26.7°C). The remaining site structures

and areas conservatively use the recorded site maximum temperature of 105°F (40.6°C). These include structures such as warehouses, office buildings, and outside support structures. Using the recorded site maximum temperature is considered conservative because of the types of structures included and the daily and seasonal variations in site ambient temperature.

A summary of the radiation environments is presented in Replacement Table 3.2-2 of Exhibit A of the Application, whose values are the design radiation maximums specific to normal operation and are obtained from the environmental qualification criteria manual. These values are considered conservative maximums; the actual 40-year dose will be lower. For all areas of the plant not listed in the environmental qualification criteria manual, the 40-year dose (gamma) is negligible. The expected normal dose for 60 years is determined by multiplying the current 40-year normal dose by a ratio of 1.5.

Section 3.2.2.3 of Exhibit A of the Application presents a description of moisture environments. Although many plant areas could be subjected to a one-time pipe leak, of concern for long-term aging are areas where components are subjected to wetting. Wetting refers to a significant amount of moisture in contact with components such as would be produced by repeated instances of standing water, system leakage/spray, or flooding. Many electrical components included in the aging management review are exposed to outside ambient conditions, which include all forms of precipitation. Some insulated cables are exposed to other potential moisture areas that are identified in Replacement Table 3.6-3 of Exhibit A of the Application. Areas subject to moisture were identified based on observations and walkdowns.

As discussed in the Response to RAI 2.6-1, determining whether a component is subject to an aging management review based on its location is no longer used in the scoping of electrical components.

NOTE: RAIs 2.6-9, 2.6.1-1, 2.6.1-2, 2.6.1-3, 2.6.1-4, and 2.6.1-7 stem from staff review of a document that is not part of the Application. In addition to reviewing the responses to these RAIs, the reviewer is encouraged to read the Response to RAI 2.6-1.

RAI 2.6-9 (11/25/98A)
0SS-0274.00-00-0006 dated September 10, 1998, Revision 0, excludes uninsulated ground conductors in Section 11 from an aging management review on the basis of system function. In addition, it is stated that there are no failures of uninsulated ground conductors that could prevent satisfactory accomplishment of any of the functions identified in 10 CFR Part 54.4 (a)(1)(i), (ii), or (iii).

Provide the basis for this statement. Discuss whether a failure mode and effects analysis was performed to arrive at this conclusion.

Response to RAI 2.6-9
NOTE: This RAI stems from staff review of a document that is not part of the Application. In addition to reviewing the responses to this RAI, the reviewer is encouraged to read the Response to RAI 2.6-1.

The statement referenced in the RAI is the conclusion reached after applying the criteria of §54.4(a)(2) to uninsulated ground conductors. Guidance for applying the criteria of §54.4(a)(2) is provided in Section III.c.(iii) of the statement of considerations (SOC) accompanying the issuance of 10 CFR 54. This SOC guidance is applied to uninsulated ground conductors with the conclusion that uninsulated ground conductor failures meet the hypothetical failure attributes as discussed in the SOC. Therefore, uninsulated ground conductors failures, per the SOC guidance, are hypothetical and are not required to be considered.

The statement referenced in the RAI could more accurately have stated that there are no failures of uninsulated ground conductors, which are required to be considered, that could prevent satisfactory accomplishment of any of the intended functions identified in §54.4 (a)(1)(i), (ii), or (iii).

Regarding whether a failure mode and effects analysis is performed to arrive at this conclusion, the single failure analysis tables in Chapter 8 of the Oconee UFSAR are included in the review and are part of the basis for the stated conclusion.

RAI 2.6.1-1 (12/01/98B)
OSS-0274.00-00-0006, Subsection 3.1.4.2, "Scoping Based on System Function," states, in part, that "[t]he second part of electrical component scoping is performed by looking at the system functions performed by the electrical components and comparing *these system functions* to the functions identified in 10 CFR 54.4." Therefore, at this stage of the process, electrical *components* are determined to require an aging management review only if the *system-level function* performed by the component meets the scoping criteria in 10 CFR 54.4.

Section 54.21(a)(1) states, in part, that "[s]tructures and components subject to an aging management review shall encompass those structures and components -- (i) [t]hat perform an *intended function, as described in 10 CFR 54.4*, without moving parts or without a change in configuration or properties." Accordingly, the staff and the industry (in NEI 95-10, Subsection 4.1.2, "Determining Structures and Components Subject to Aging Management Review and Their Intended Functions") have interpreted this requirement to mean that the selection of components subject to an aging management review should be based on *component-level intended function(s)* and not *system-level functions*. Specifically, NEI 95-10, Subsection 4.1.2, states, in part, that "[t]he structure or component intended function(s) is the *specific function* of the structure or component that supports the system intended function." [OLRP-1001 Section 2.6.1]

a. Please describe the process used by Duke to identify the *system function(s)* performed by electrical *components* and how this process confirms that the *intended function(s)* (as defined in NEI 95-10) of electrical components has been identified.
b. Please provide a justification for using *system-level functions* to exclude electrical components from requiring an aging management review.

Response to RAI 2.6.1-1 (12/01/98B)
NOTE: This RAI stems from staff review of a document that is not part of the Application. In addition to reviewing the responses to this RAI, the reviewer is encouraged to read the Response to RAI 2.6-1.

Duke identified intended functions performed by an electrical component using several information sources such as the UFSAR, design basis documents, and interviews with system and component experts. If the functions a component performs do not meet the criteria of §54.4(a), the component is not within scope and can be excluded from an aging management review.

The terms "system intended function" and "component intended function" have only a semantic difference as used in the document identified in the RAI. The specific "labeling" of the scoping steps performed may not be in agreement with NEI 95-10 Rev. 0 but the basic process followed is in agreement. Scoping of electrical components consisted of:

(1) Identifying the functions performed by a component
(2) Comparing the functions performed by a component to the criteria of §54.4(a) in order to determine its applicability

Further details on scoping and the application of §54.4(a) criteria to electrical components are provided in the Response to RAI 2.6-1.

RAI 2.6.1-2 (12/01/98B)
OSS-0274.00-00.0006, Subsection 3.1.4.2.1, "Bounding The Actual Set of In-Scope Components," states that "[w]hen applying the 10 CFR 54.4 scoping criteria to the electrical components, it is necessary to identify the higher level system functions performed by the electrical component type and compare these system functions - in the context of the Oconee current licensing basis (CLB) - to the functions identified in 10 CFR 54.4." However, this subsection also adds: "When component identification per 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(2) is not clear or workable, a larger, bounding set of electrical components is identified." [OLRP-1001 Section 2.6.1]

a. Please explain why "component identification per 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(2) is not clear or workable at Oconee" and describe how Duke can demonstrate compliance with the scoping requirements of 10 CFR 54.4(a) when this is the case.

b. Please describe the extent to which the OSRDC results were used by Duke when component identification per 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(2) was not clear or workable. If the OSRDC results were not used, please provide justification.

Response to RAI 2.6.1-2
NOTE: This RAI stems from staff review of a document that is not part of the Application. In addition to reviewing the responses to this RAI, the reviewer is encouraged to read the Response to RAI 2.6-1.

In some cases, identification of the exact set of electrical components that meet the criteria of §54.4(a)(1) and (2) would be very time consuming. This is due to the differences between the Oconee current licensing basis (CLB) definition of "safety-related" and the definition of

"safety-related" provided in §54.4(a)(1). In most cases, an electrical component designated as "safety-related" at Oconee also meets the criteria of §54.4(a)(1). It may take much more investigation and study to determine if an Oconee "nonsafety-related" component meets the criteria of §54.4(a)(1) or (2). Using the phrase "not clear or workable" is not the best choice of words to describe this.

The Oconee electrical component integrated plant assessment took an encompassing group approach to the application of §54.4(a) criteria when a defined group contained both Oconee CLB defined "safety-related" and "nonsafety-related" components. Electrical components in the 230 kV Switchyard serves as an example. The two main buses in the 230 kV Switchyard are the Red Bus and the Yellow Bus. Generally, components associated with the Red Bus are nonsafety-related and components associated with the Yellow Bus are safety-related. The boundary between the Oconee CLB safety-related and nonsafety-related components in the switchyard is well defined, but that boundary uses the Oconee CLB safety-related definition. In order to apply the §54.4(a) criteria to the components in the switchyard, all functions of each component in the switchyard would need to be identified so it could be compared to the criteria of §54.4(a). This task would be labor intensive.

As an alternative, all components installed in the 230 kV Switchyard are included in the aging management review as part of an encompassing group, which eliminates the need to identify individual component functions for scoping. Various commodity groups in the 230 kV Switchyard such as switchyard bus, transmission conductors, and insulators are examples of encompassing groups.

The encompassing group approach to scoping is used for several commodity groups as shown in Column 3 of RAI Response Table 2.6-1 in the Response to RAI 2.6-1. In each of these cases, an encompassing group of components is identified which includes all components that meet the §54.4(a) criteria and, in addition, includes some components that may not meet the §54.4(a) criteria. All electrical components within each encompassing group are included in the aging management review. Identification of an encompassing group of components is allowed as discussed in Section III.f.(ii) of the statement of considerations (SOC) for 10 CFR 54.

The Oconee Safety-Related Designation Clarification (OSRDC) project results are not used whenever an encompassing group of electrical components is chosen to be included in the aging management review. The inclusion of an encompassing group of electrical components in the aging management review produced complete and accurate results while eliminating the need for the more specific scoping provided by the OSRDC documentation.

The OSRDC results are used to validate the scoping of electrical components when the scoping indicated that the electrical components did not meet the criteria of §54.4(a).

RAI 2.6.1-3 (12/01/98B)
OSS-0274.00-00.0006, Subsection 3.2.1, "10 CFR 54.21(a)(1)(i) Determination," states that "[t]he starting point of this determination is the generation of the list of all electrical component types along with identification of the basic component functions." Subsection 3.2.2, 10 CFR 54.4, "Scoping," adds: "The system function scoping is performed based *strictly* on the functions the component performs within its system *as described in Oconee current licensing basis (CLB) documents*."

Section 54.21(a)(1) states, in part, that "[s]tructures and components subject to an aging management review shall encompass those structures and components -- (i) [t]hat perform an *intended function, as described in 10 CFR 54.4*, without moving parts or without a change in configuration or properties." Accordingly, the staff and the industry (in NEI 95-10, Section 4.0 and Section 4.1.2) have interpreted this requirement to mean that the active/passive determination should be performed using component-level intended function that is based on the criteria under 10 CFR 54.4(a). [OLRP-1001 Section 2.6.1]

a. Based on the above, the staff requests that Duke provide its basis for concluding that the approach described in OSS-0274.00-00.0006, Subsection 3.2.1, is consistent with the requirements of the rule.
b. Regarding the system function scoping approach described in OSS-0274.00-00.0006, Subsection 3.2.1, please describe the extent to which the OSRDC results were used by Duke. If such results were not used, please provide justification.

Response to RAI 2.6.1-3
NOTE: This RAI stems from staff review of a document that is not part of the Application. In addition to reviewing the responses to this RAI, the reviewer is encouraged to read the Response to RAI 2.6-1.

Subsection 3.2.1 of the Oconee electrical component integrated plant assessment basis document is the section pertaining to the application of §54.21(a)(1)(i) criteria (screening) to electrical components. Subsection 3.2.2 of the basis document is the section pertaining to the application of §54.4(a) criteria (scoping) to electrical components. Statements made regarding §54.4(a) scoping do not pertain to and are not in addition to statements made regarding §54.21(a)(1)(i) screening. These are two separate and distinct steps in the electrical component integrated plant assessment.

a. As noted in this RAI, the §54.21(a)(1)(i) determination should be performed using "component-level" intended functions. The process used to make §54.21(a)(1)(i) determinations for electrical components is provided in the last sentence of the paragraph of Subsection 3.2.1 quoted in the RAI which states that the §54.21(a)(1)(i) determination is made based on the way the component performs its intended function. This determination deals only with the component-level intended function. This is consistent with the guidance in NEI 95-10 Rev. 0 and the requirements of the license renewal rule.

b. Subsection 3.2.1 of the Oconee electrical component integrated plant assessment basis document is the section pertaining to the application of §54.21(a)(1)(i) criteria (screening) to electrical components and does not pertain to §54.4(a) scoping. Oconee Safety-Related Designation Clarification (OSRDC) project results are used to validate the scoping of electrical components when the scoping indicated that the electrical components did not meet the criteria of §54.4(a).

RAI 2.6.1-4 (12/01/98B)
OSS-0274.00-00.0006, Subsection 3.1.5, "Determine Which Electrical Components Are Subject To Replacement Based On A Qualified Life Or Specified Time Period," states that "[t]his step is accomplished by investigating each electrical component type within scope to determine if any plant program or procedure identifies a *time-based component life and has provisions to replace the component prior to the end of its life*.

Section 54.21(a)(1) states, in part, that "[s]tructures and components subject to an aging management review shall encompass those structures and components -- (ii) *That are not subject to replacement based on a qualified life or specified time period*." [OLRP-1001 Section 2.6.1]

Please describe the difference, if any, between the requirements of the rule and the language in OSS-0274.00-00.0006, Subsection 3.1.5, regarding the identification of structures and components *not subject to replacement based on a qualified life or specified time period.* Specifically:

a. Describe the criteria used by Duke for determining that an electrical component type has a *time-based component life*.

b. Define what constitute *provisions* [in any plant program or procedure] *to replace the component prior to the end of its life.*

c. Identify the difference, if any, between the term "time-based component life" as used in OSS-0274.00-00.0006, Subsection 3.1.5, and the term "qualified life" as used in 10 CFR 54.21(a)(1)(ii).

Response to RAI 2.6.1-4

NOTE: This RAI stems from staff review of a document that is not part of the Application. In addition to reviewing the responses to this RAI, the reviewer is encouraged to read the Response to RAI 2.6-1.

a. The only criteria used by Duke to apply §54.21(a)(1)(ii) to electrical components is that contained in §54.21(a)(1)(ii) and the accompanying guidance in Section III.f.(i)(b) of the statement of considerations for 10 CFR 54. The application of this criteria and guidance is described in the Response to RAI 2.6-1. RAI Response Table 2.6-1 in the Response to RAI 2.6-1 summarizes the results of applying the criteria of §54.21(a)(1)(ii) to applicable electrical components.

b. The phrase "*provisions to replace the component prior to the end of its life*" refers to components in the Oconee EQ program. The EQ program ensures that equipment replacement is scheduled and implemented before the end of the equipment qualified life. Information regarding the Oconee EQ program is provided in the Response to RAIs 5.6-1, 5.6-2, and 5.6-3 which are provided as Attachment 3 to Duke letter to the NRC dated February 8, 1999.

c. The term "time-based component life" means the same thing as "qualified life" when used in the context of applying the criteria of §54.21(a)(1)(ii). See the Response to RAI 5.6-1, RAI 5.6-2, and RAI 5.6-3 for further information on the Oconee EQ program.

RAI 2.6.7-1 (12/01/98B)
In Appendix A, "Scoping Electrical Components Based on Their Installed Location," to OSS-0274.00-00.0006, electrical components associated with the 100kV transmission line and Transformer CT5 were excluded from the scope of license renewal based solely (apparently) on the determination that structures associated with the 100kV transmission line and Transformer CT5 were not classified as Class 1 or Class 2 in the Oconee UFSAR, and therefore, are considered Class 3.

Appendix A states that "[t]here are Class 1, Class 2, and Class 3 structures where Class 1 and Class 2 structures are within license renewal scope and Class 3 structures are not within license renewal scope [Reference 10, Chapter 3]. Appendix A also adds that "there is reasonable assurance that if a structure is *not* identified as required to demonstrate compliance with the regulated events identified in 10 CFR 54.4(a)(3), it does *not* support any electrical components needed to meet the requirements of 10 CFR 54.4(a)(3)." [OLRP-1001 Sections 2.6.7 and 2.7.1]

a. Please describe the extent to which the OSRDC project results were used to reach the conclusion that structures associated with Transformer CT5 and the 100kV transmission line are Class 3. If such results were not used, please provide justification. This justification should address the role of Transformer CT5 and the 100kV transmission line in the Oconee Technical Specifications and Emergency Operating Procedures.

b. Please describe the methodology used during the scoping process of Oconee *structures* to identify *all electrical components* that perform the functions identified in 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), or 10 CFR 54.4(a)(3). If the electrical components were not explicitly identified during this process, please provide justification for Duke's reliance on installed location for scoping electrical components.

c. Please describe the extent to which the OSRDC project results were used during the scoping process of Oconee *structures* to identify *all electrical components* that perform the functions identified in 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), or 10 CFR 54.4(a)(3). If the OSRDC project results were not used, please provide justification.

Response to RAI 2.6.7-1

NOTE: This RAI stems from staff review of a document that is not part of the Application. In addition to reviewing the responses to this RAI, the reviewer is encouraged to read the Response to RAI 2.6-1.

a. The OSRDC results are not used to determine that structures associated with Transformer CT5 and the 100 kV transmission line are Class 3. Oconee UFSAR Section 3.2.1.1 identifies all Class 1 and 2 structures, and no structures associated with Transformer CT5 and the 100 kV transmission line are identified. Therefore, structures associated with Transformer CT5 and the 100 kV transmission line classified as Class 3. This is the Oconee current licensing basis (CLB). A study was conducted which reviewed the information generated by the Oconee Safety-Related Designation Clarification (OSRDC) project. This study confirmed that Transformer CT5 and the 100 kV Fant Black transmission line are not required during or following any design basis event. Technical Specifications and Emergency Operating Procedures are not within the scoping criteria of §54.4.

b. Electrical components are not identified during the scoping process of Oconee structures. As discussed in the Response to RAI 2.6-1, Duke is opting for a more conservative approach that no longer eliminates electrical components from the aging management review based on their being supported by a specific class of structure.

c. This RAI is fully answered in the Response to RAI 2.6-1. As discussed in the Response to RAI 2.6-1, Duke is opting for a more conservative approach that no longer eliminates electrical components from the aging management review based on their being supported by a specific class of structure.

Set # 04
February 17, 1999

RAI 2.6.7-2 (12/01/98B)
In OLRP-1001, Subsection 2.6.7, "Structures and Areas Containing Electrical Components Subject to Aging Management Review," Duke states, in part, that "[b]y eliminating structures and areas that do not contain any electrical components that are within the scope of license renewal and by adding direct buried cables as part of Yard Structures, the structures and areas that contain electrical components within the scope of license renewal are identified." [OLRP-1001 Section 2.6.7]

a. Please describe in detail the process used by Duke to identify all the Oconee "structures and areas that do not contain any electrical components that are within the scope of license renewal."

b. Please describe the extent to which the OSRDC project results were used in this process. If they were not used, please provide justification.

Response to RAI 2.6.7-2
The questions in this RAI are fully answered in the Response to RAI 2.6-1. As discussed in the Response to RAI 2.6-1, Duke is opting for a more conservative approach that no longer eliminates electrical components from the aging management review based on their being supported by a specific class of structure.

RAI 3.2-1 (11/25/98A)
Section 3.2 of the application identified thermal, radiation, and moisture as the service environment stressors in which components operate that may result in aging effects of concern for license renewal.

In addition to the above identified service environment stressors, discuss the potential aging effects that may occur at Oconee for license renewal due to humidity, water spray, steam, water immersion, chemicals, (including sprays) vibration and seismic motion and operational stressors produced by equipment operation.

Response to RAI 3.2-1
Humidity and water immersion are included in the consideration of moisture as an environmental stressor. Aging effects caused by exposure to moisture are addressed in Sections 3.6.2.1.1, 3.6.3.1, 3.6.4.1, and 3.6.5.1 and Replacement Section 3.6.2.2.1 of Exhibit A of the Application.

Water spray, steam, chemical sprays, exposure to chemicals, and seismic motion are event driven stressors and are not aging stressors. As stated in Section 3.2.2.3 of Exhibit A of the Application, event driven occurrences are not considered in license renewal aging management reviews.

Self-heating temperature rise is the only operational stressor produced by equipment operation that is applicable to electrical components included in the aging management review. Self-heating temperature rise is incorporated into the review of applicable aging effects in Sections 3.6.2.1.1, 3.6.3.1, 3.6.4.1, and 3.6.5.1 and Replacement Section 3.6.2.2.1, of Exhibit A of the Application.

Vibration for the isolated-phase bus, nonsegregated-phase bus, segregated-phase bus, and switchyard bus is addressed in the Response to RAI 3.6-1. Vibration for insulated cables and connections is addressed in the Response to RAI 3.6-2.

Transmission conductor vibration would be caused by wing loading. Wind loading that can cause a transmission line and insulators to vibrate is considered in the design and installation. Loss of material (wear) and fatigue that could be caused by transmission conductor vibration or sway are found not to be applicable aging effects in that they would not cause a loss of intended function if left unmanaged for the extended period of operation. Vibration of insulators and transmission conductors is not identified in NRC generic communications, industry experience, or relevant Oconee operating experience and, therefore, is not a potential aging effect that warrants review.

RAI 3.6-1 (11/25/98A)
Section 3.6.2 of the application discusses stressors such as connection surface oxidation, temperature, radiation, and precipitation and their applicable aging effects on the isolated-phase, nonsegregated-phase, segregated-phase, and switchyard buses.

Discuss whether vibration was considered as a stressor and list any applicable aging effects due to vibration for each of the above electrical buses.

Response to RAI 3.6-1
Nonsegregated-phase, segregated-phase, and switchyard buses are connected to static equipment that does not normally vibrate such as switchgear, transformers, and transmission conductors. These buses are all supported by static structural components such as cement footings and building steel. With no connections to dynamic equipment, vibration is not an applicable stressor for these buses and aging effects due to vibration are not applicable. Isolated-phase bus, in addition to being connected to static equipment, is connected to the unit generators through flexible conductors. These flexible conductors prevent generator vibrations from propagating into the rigid isolated-phase bus. Vibration is not an applicable stressor for isolated-phase bus and aging effects due to vibration are not applicable. Vibration of isolated-phase, nonsegregated-phase, segregated-phase, and switchyard buses is not identified in NRC generic communications, industry experience, or relevant Oconee operating experience. No applicable aging effects due to vibration exist for isolated-phase bus, nonsegregated-phase bus, segregated-phase bus, and switchyard bus.

RAI 3.6-2 (11/25/98A)
Section 3.6.3 of the application identifies temperature, radiation, and moisture as the principal environmental stressors that insulated cables and connections are exposed to. Discuss the aging impact of the following operational and environmental stressors as identified in Reference 3.6-1 on the Oconee insulated cables and connectors:

a. Electrical stressors
   - Energization at normal voltage levels
   - Transient conditions
   - Partial discharge
   - Effects of contaminants
   - Water treeing
   - Indications of electrical degradation
   - Effects of high-potential testing on XLPE-insulated cables

b. Mechanical stressors
   - Vibration

- Gravity-induced cable "creep" and tensile stress
- Compression
- Installation related-degradation
- Maintenance/operation-related degradation

c. Chemical/Electrochemical stressors
- Chemical attack of organics and cable decomposition
- Electro-mechanical attack of metal
- Loss of fire retardants
- Effects of oxygen and ozone

Response to RAI 3.6-2
The list of operational and environmental stressors identified in the RAI came from the referenced report which was published by the Department of Energy (DOE); SAND96-0344, *Aging Management Guideline for Commercial Nuclear Power Plants – Electrical Cable and Terminations* (DOE Cable AMG) [Reference 3.6-1 of Exhibit A of the Application]. Two of the operational and environmental stressors, water treeing in medium voltage cables and electro-chemical attack of metals, are currently addressed as follows:

- **Water Treeing**

Water treeing is addressed in Replacement Section 3.6.3.1.2 of Exhibit A of the Application, "*Medium-Voltage Cable — Moisture*," provided in the Response to RAI 2.6-1.

- **Electro-chemical Attack of Metals**

Electro-chemical attack of metals relates to corrosion and oxidation of low-voltage connectors and is addressed in Section 3.6.3.1.1 of Exhibit A of the Application, "*Low-Voltage Connector — Moisture*."

The remaining aging mechanisms identified in the RAI are categorized in the DOE Cable AMG as being "significant." The DOE Cable AMG categorizes aging mechanisms as being either "significant" or "significant and observed." Under the direction of the DOE, all possible (including hypothetical) aging mechanisms were to be included in the AMG. Drafts of the AMG initially indicated that most of the aging mechanisms are not significant (i.e., not important or of consequence). However, in the final document, these same aging mechanisms are identified as "significant" and a new classification of "significant and observed" is used to identify those mechanisms that are observed in the industry.

Section 4.2 of the AMG emphasized that "*the applicability of some aging mechanisms to actual cable systems may be very limited or the frequency of their occurrence may be extremely low*"...[and]..."*even these principal aging mechanisms are often of little consequence to the continued functionality of the plant cable systems as a whole.*" After a

consideration of all the stressors and the reported incidence of their effects in the industry, the AMG concluded that "*the likelihood of substantially increased effects or failure rate resulting from aging mechanisms currently categorized only as 'significant' is considered low.*"

All of the environmental and operational stressors discussed in the following paragraphs are categorized in the DOE Cable AMG as being only "significant," not "significant and observed."

a. Electrical Stressors

- **Energization at Normal Voltage Levels**

The amount and severity of this stress is determined primarily by the dielectric strength and thickness of the insulating material used, and the operating voltage and frequency. Published data indicate that insulation breakdown due to energization at normal operating voltages is of limited concern, based on the comparatively low applied voltage stress. Cables are designed to specific voltage ratings that equal or exceed the cable operating voltage. Therefore, energization at normal voltage levels is not a significant stressor and associated aging effects are not applicable.

- **Transient Conditions**

Voltage and current surges can stress the dielectrics of the cable and associated connections and contribute to breakdown of insulation. These transients are considered in the design and selection of electrical system components. Cables are manufactured, selected, and installed with sufficient insulation thickness to withstand voltage stress, and connections are matched to the performance of the cable system. Therefore, transient conditions are not significant stressors and associated aging effects are not applicable.

- **Partial Discharge**

This effect results from large potential gradients between materials separated by air or similar media. Partial discharge can occur between conducting components internal to the cable structure or between insulators separated by a gaseous medium. Factory testing, installation, and termination techniques are designed to preclude partial discharge. Partial discharge is a consequence of improper manufacturing or termination techniques, is not age-related, and does not require an aging management review.

- **Effects of *[Moisture and]* Contaminants**

The title of this stressor in the DOE Cable AMG is "Effects of Moisture and Contaminants." Dry contaminants cause no aging effects. Moisture is addressed in Replacement Section 3.6.3.1.2 of Exhibit A of the Application as superseded in the Response to RAI 2.6-1.

- **Indications of Electrical Degradation**

This discussion topic in the DOE Cable AMG is intended to be illustrative of other *indications* of aging. However, the topic is not an aging mechanism itself and does not identify any new aging mechanisms that are not already addressed in the other discussions.

- **Effects of High-potential Testing on XLPE-insulated Cables**

High-potential testing is only performed on shielded, medium-voltage cables. Oconee does not use XLPE-insulated cables in medium-voltage applications. Therefore, this aging stressor is not applicable.

b. Mechanical Stressors

- **Vibration**

Vibration is generally induced in cables and connections by the operation of external equipment such as compressors, fans, and pumps. Vibration can affect cable connections at a running motor by producing fatigue damage of the metallic cable or termination components in the immediate vicinity of the connection point. Terminations at equipment are considered part of the equipment and are inspected and maintained as part of the equipment. These terminations are not within the evaluation boundary for insulated cable and connections and are not included in the insulated cable and connection review.

- **Gravity-induced Cable "Creep" and Tensile Stress**

Proper installation techniques including softened edges, rounded supports, proper supports, and limitations on cable tray loading preclude gravity-induced cable creep and tensile stress. Gravity-induced cable creep and tensile stress is a consequence of improper installation, is not age-related, and does not require an aging management review.

- **Compression**

This aging stressor is not applicable to cables; it is of interest for o-rings, seals, gaskets, and grommets used in connectors. O-rings, seals, gaskets, and grommets used in connectors are replaced as necessary during routine maintenance. Therefore, these are consumable parts and compression is not an applicable stressor.

- **Installation-related Degradation**

Degradation during cable installation is not an aging mechanism. Installation damage to cables might occur, but such damage is not age related and does not require an aging management review.

- **Maintenance/Operation-related**

Degradation resulting from manipulation of cables and connections during maintenance or testing is not an aging mechanism. External mechanical stresses may cause damage, but the stresses are not age related and do not require an aging management review.

c. Chemical/Electrochemical stressors

- **Chemical Attack of Organics and Cable Decomposition**

There are no in-scope insulated cables and connections that are normally exposed to chemicals or chemical sprays during normal plant operating conditions. A chemical spill is event-driven; it is not an aging mechanism. The effects of random, inadvertent chemical spills, should they occur, would be evaluated at the time of the spill on a case-by-case basis. Therefore, chemical/electrochemical stressors are not applicable.

- **Loss of Fire Retardants**

Loss of fire-retardant compounds in cable insulation and jacketing due to thermal aging or irradiation is considered insignificant. It has been demonstrated that the actual flammability of the most common insulation and jacketing materials (including XLPE, EPR, and CSPE) either decreases, remains roughly constant, or only increases slightly, due to the competing effect of loss of other flammable volatiles within the chemical formulation. Therefore, aging effects associated with loss of fire retardants are not applicable.

- **Effects of Oxygen and Ozone**

The effects of oxygen on aging involve the percent concentration of oxygen during the aging process (that is, the rate of aging can change for some materials if the percent of oxygen is less than ~20%). However, the typical thermal aging tests that are cited as the basis for aging studies involving the types of cables installed at Oconee were performed in forced-convection air ovens. Therefore, the concentration of oxygen in both the tests and the installed locations are similar, and this stressor will not affect the rate of aging.

Degradation of certain organic insulation and jacketing materials may be affected by Ozone, which is generated as the result of the interaction of ionizing radiation with oxygen or by corona discharge ionization. Technical literature that addresses this aging stressor notes that it is applicable to SBR and Buna-N rubber. SBR and Buna-N are not used as cable insulations at Oconee. In summary, neither oxygen nor ozone effects are applicable.

RAI 3.6-3 (11/25/98A)
Section 3.6.4 of the application discusses cracking, loss of material due to wear, and surface contamination as potential aging effects for insulators.

Discuss the aging significance of rust formation where galvanizing is burnt off the insulator due to flash-over from lightning strikes, and the inspection process that will detect loss of material due to rust.

Response to RAI 3.6-3
Section 3.6.4.1.2 of Exhibit A of the Application stated that *surface* rust might form where galvanizing is burnt off due to flashover from lightning strikes. Surface rust is not a significant concern and would not cause a loss of intended function if left unmanaged for the extended period of operation. Therefore, loss of material due to *surface* rust where galvanizing is burnt off due to flashover from lightning strikes is not an applicable aging effect. Inspections as part of an aging management program are not required since there are no applicable aging effects.

RAI 3.6-4 (11/25/98A)
Section 3.6.5 of the application lists loss of conductor strength as the only aging effect for transmission line conductors due to corrosion of the steel core and aluminum strand pitting. Since corrosion can lead to loss of material, and ultimate conductor failure, what percent of composite conductor strength would require transmission conductor replacement and how would that parameter be measured?

Response to RAI 3.6-4
No set percentage of composite conductor strength is established at which a transmission conductor is replaced. As illustrated below, there is ample strength margin to maintain the transmission conductor intended function through the extended period of operation.

The National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60% of the ultimate conductor strength. The NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which includes consideration of ice, wind, and temperature. These requirements are reviewed concerning the specific conductors included in the aging management review. The conductors with the smallest ultimate strength margin are 4/0 ACSR (aluminum conductor steel reinforced) will be used as an illustration.

The ultimate strength and the NESC heavy load tension requirements of 4/0 ACSR are 8350 lbs. and 2761 lbs. respectively. The margin between the NESC Heavy Load and the ultimate strength is 5589 lb.; i.e., there is a 67% of ultimate strength margin. The Ontario Hydroelectric study [Reference 3.6-5 of Exhibit A of the Application] showed a 30% loss of composite conductor strength in an 80-year-old conductor. In the case of the 4/0 ACSR transmission conductors, a 30% loss of ultimate strength would mean that there would still be a 37% ultimate strength margin between what is required by the NESC and the actual conductor strength.

The 4/0 ACSR conductors have the lowest initial design margin of any transmission conductors included in the aging management review. This illustrates with reasonable assurance the transmission conductors will have ample strength through the period of extended operation.

ATTACHMENT 4

Oconee Nuclear Station

Application for Renewed Operating Licenses

Responses to NRC Requests for Additional Information (RAI)

Set # 04
February 17, 1999

Consumables

Introduction

A number of questions have been raised by the NRC concerning the aging management of consumables. Prior to answering the RAIs that address consumables, Duke Energy would like to provide some background discussion to aid the reviewer. The effects of aging are cumulative throughout the life of the plant. One way to effectively manage these aging effects is to replace the component either on a specified interval based on a qualified life or periodically based on a specified time period. The NRC has incorporated these two concepts into §54.21(a)(1)(ii).

Replacement can also be based on a performance or condition monitoring program which is discussed in the Section III.f.(i)(b) of the Statement of Consideration (SOC) of 10 CFR Part 54. The NRC decided not to generically exclude passive structures and components that are replaced based on performance or condition from an aging management review. However, the NRC did not preclude an applicant from providing site-specific justification that a replacement program based on component performance provides reasonable assurance that the intended function of the component will be maintained in the period of extended operation.

> SOC to 10 CFR Part 54, Section III.f.(i)(b)
> *However, the Commission does not intend to preclude a license renewal applicant from providing site-specific justification in a license renewal application that a replacement program on the basis of performance or condition for a passive structure or component provides reasonable assurance that the intended function of the passive structure or component will be maintained in the period of extended operation.*

The expected attributes of this replacement program are also provided in the Section III.f. (i)(b) of the SOC of 10 CFR Part 54.

> SOC to 10 CFR Part 54, Section III.f.(i)(b)
> *... the Commission would generally expect that such a replacement program would have defined performance or condition measuring methods (e.g., wall thickness of heat exchanger tubes), an established monitoring frequency that supports timely discovery of degraded conditions (e.g., every refueling outage), and an appropriate replacement criterion (e.g., upon reaching a specified number of tubes plugged).*

In consideration of the statements in the SOC, Duke Energy has determined that components that are subject to replacement based on a qualified life, specified time period or as a result of performance or condition monitoring (as approved by NRC on a case by case basis) are short-lived components. Consumables are materials and supplies expended during normal operation or maintenance of systems, structures and components.

The program or activity relied upon to replace the consumable when its condition indicates it is no longer acceptable for service is identified in the response to the consumable RAI. Program or activity attributes as described in Section III.f.(i)(b) of the SOC to 10 CFR Part 54 are also discussed in the RAI response. See Duke responses to RAIs 1.5.2-1, 2.2-5, 2.4-4, 2.5.8-4, 2.7-1, 3.3-19, 3.7.1-1, 3.7.3-4, 3.7.3-8, 3.7.5-2, 3.7.6-3, 3.7.6-6, 3.7.7-3, and 3.7.9-2 which address short-lived components, consumables, and the associated replacement program or activity.

RAI 1.5.2-1
The application states that an aging management review is not required for the reactor coolant pump seals because they are generally replaced "approximately every four operating cycles" or "approximately every two operating cycles" depending on the component. The license renewal rule allows a component to be eliminated from an aging management review if it is subject to periodic replacement, based on a qualified life or a specified time period. Please describe the controlled replacement program which establishes a specific replacement frequency or interval (or upper limit replacement interval), based on a qualified life or a specified time period.

Response to RAI 1.5.2-1
Reactor coolant pump seals are replaced in accordance with requirements contained in the Engineering Support Program at Oconee. The program requires periodically monitoring the performance of the seals and trending of the results. Unless performance trends indicate an earlier replacement, the seals are replaced on the following schedule, which supercedes the schedule provided in Section 1.5.2 of Exhibit A of the Application.

For Oconee Units 2 and 3 (Bingham reactor coolant pumps) and the first stage of the Westinghouse reactor coolant pumps on Unit 1, the reactor coolant pump seals are replaced on an interval not to exceed every four operating cycles. The second and third stages of the Westinghouse reactor coolant pump seals on Unit 1 are replaced on an interval not to exceed every two operating cycles. Because replacement of reactor coolant pumps seals occurs routinely, they are not subject to aging management review for the license renewal period of extended operation.

RAI 2.2-5 (11/30/98B)
Fire protection equipment such as hoses, scott air packs, and fire extinguishers were not considered in the license renewal application. These types of components appear to be within scope according to 10 CFR 54.4(a)(3). Please provide the justification for excluding these components from the scope of license renewal. In addition, the components appear to perform an intended function without moving parts or change in configuration or properties, and do not appear to be subject to replacement based on a qualified life or specified time period, per 10 CFR 54.21(a)(1). Therefore, justify exclusion of these components from aging management review.

Response to RAI 2.2-5
Fire hoses, scott air packs and fire extinguishers are considered by Duke Energy to be consumables. As explained in detail in the Introduction to Attachment 4, Section III.f.(i)(b) of the SOC to 10 CFR Part 54 allows an applicant to determine that the replacement of a structure or component based on performance or condition provides reasonable assurance that the intended function of the passive structure of component will be maintained in the period of extended operation. The *Fire Protection Program* determines the replacement of the fire hoses, scott air packs and fire extinguishers.

The fire hoses, scott air packs, and fire extinguishers are routinely checked by inspections performed under the Oconee *Fire Protection Program.* The *Fire Protection Program* meets the requirements of applicable NFPA codes. Fire hoses are inspected and pressure tested periodically and must be replaced if they do not pass the test or inspection. Scott air packs are periodically tested and must be replaced if they do not pass the test. Each fire extinguisher has a qualified life and must be replaced at the end of the qualified life.

Specific inspection methods, frequency and acceptance criteria are provided within this program and the applicable NFPA codes. For fire hoses, scott air packs, and fire extinguishers, the programmatic action is not to "manage" their life, but rather to replace them when their condition indicates they are no longer acceptable for service. Therefore, fire hoses, scott air packs, and fire extinguishers are replaced based on qualified life, performance, or condition and, thus, are not subject to aging management review.

RAI 2.4-4

Page 4-10, Section 4.2.2.1.5 (UFSAR) [updated December 31, 1997], indicates that attached to the upper end fitting (Reactor Vessel Internals) is a holddown spring, which provides a positive holddown margin to oppose hydraulic forces resulting from the flow of the primary coolant. It was not clear from the submittal (Fig. 2.4-5) if this spring is within the scope of license renewal. It is feasible that the holddown spring may loose its required force with extended age. Discuss whether this item is within the scope of license renewal or provide a basis for its exclusion.

Response to RAI 2.4-4

The holddown spring is attached to the upper end fitting of the fuel assembly and is not attached to the reactor vessel internals. Removable upper end fittings allow fuel assembly reconstitution; however, the end fittings are retired from service when the fuel assembly is replaced for refueling. The fuel assemblies and associated upper end fittings, including the holddown springs, are periodically replaced during refueling outages and are thus not subject to aging management review in accordance with 54.21(a)(1)(ii).

RAI 2.5.8-4 (11/24/98C)
Note: The following question applies to Section 2.5.8.2
Are sealant materials used to control the unfiltered inleakages? If so, explain why they should or should not be included within the scope of license renewal and considered for aging management review.

Response to RAI 2.5.8-4
Sealant materials used to control unfiltered inleakages are considered by Duke Energy to be consumables. As explained in detail in the Introduction to Attachment 4, Section III.f.(i)(b) of the SOC to 10 CFR Part 54 allows an applicant to determine that the replacement of a structure or component based on performance or condition provides reasonable assurance that the intended function of the passive structure of component will be maintained in the period of extended operation. The *Control Room Pressure Test* determines the replacement of the sealant materials.

Materials used at Oconee to seal the control room areas include mastic on the ventilation ductwork, seals around wall penetrations, and door seals on Control Room access doors. The condition of these sealant materials is determined during the *Control Room Pressure Tests* conducted in accordance with technical specifications (Oconee Improved Technical Specification ITS 3.7.9, Surveillance Requirement SR 3.7.9.2). The test acceptance criterion is specified in SR 3.7.9.2. Failure to meet the specified acceptance criteria during testing requires prompt action to correct the leaking seal by either repair or replacement. In addition, the requirement to maintain a positive pressure within the control room area is a function that is maintained under the Maintenance Rule (§50.65) program. For the sealant materials, the programmatic action is not to "manage" sealant life, but rather to replace the sealant when its condition indicates it is no longer acceptable for service. Therefore, sealant materials used to control unfiltered inleakage are repaired or replaced based upon performance or condition and, thus, are not subject to aging management review.

Set # 04
February 17, 1999

RAI 2.7-1 (11-18-98A)
Section 2.7.2 of OLRP-1001 provides a list of concrete structural and steel components which are within the scope of license renewal and subject to aging management review (AMR). With regard to the scoping of structures and structural components (concrete and steel), address the following questions:

a. Are there any electrical duct banks and steel structural frames at Oconee? If yes, provide basis for not including these structural components in the scope of AMR.

b. Provide basis for not including crane columns, trolleys and mechanical cables in the scope of AMR.

c. Section 2.7.2.2.1 provides a description of various types of pipe supports. Are there any safety-related piping systems supported by structural frames? If yes, provide an explanation how these frames are covered in the AMR.

d. Provide basis for not considering the steel bracings between steel columns as steel components in an air environment in the AMR.

Response to RAI 2.7-1
a. Electrical duct banks are not used at Oconee Nuclear Station. Structural steel frames are used at Oconee Nuclear Station and are included in the components listed as Structural Steel Beams, Columns, Plates & Trusses in Section 2.7 of Exhibit A of the Application.

b. Crane columns and trolleys are included in the components listed as Structural Steel Beams, Columns, Plates & Trusses in Section 2.7 of Exhibit A of the Application. Crane columns and trolleys are routinely inspected and tested under the *Crane Inspection Program*. This program is described in Section 4.11 of Exhibit A of the Application

   Mechanical cables are considered by Duke Energy to be consumables. As explained in detail in the Introduction to Attachment 4, Section III.f.(i)(b) of the SOC to 10 CFR Part 54 allows an applicant to determine that the replacement of a structure or component based on performance or condition provides reasonable assurance that the intended function of the passive structure of component will be maintained in the period of extended operation. The *Crane Inspection Program* determines the replacement of the mechanical cables.

   Mechanical cables are routinely inspected and tested under the *Crane Inspection Program*. This program is described in Section 4.11 of Exhibit A of the Application. Specific inspection methods, frequency and acceptance criteria are provided within this

program. Mechanical cable life is based on identification of wear or damage during inspections on a daily basis, when used, or quarterly and annual maintenance program inspections. For mechanical cables, the programmatic action is not to "manage" cable life, but rather to replace the cables when their condition indicates they are no longer acceptable for service. Therefore, mechanical cables are replaced based on condition monitoring and, thus, are not subject to aging management review.

c. As discussed in Section 2.7.2.2.1 of Exhibit A of the Application, some safety-related piping systems are supported by structural frames. Loss of material of these structural frames is addressed with the *Inspection Program for Civil Engineering Structures and Components*. The *Inspection Program for Civil Engineering Structures and Components* is discussed in Section 4.19.

d. Steel bracings between steel columns are included in the aging management review with the steel components in an air environment listed as Structural Steel Beams, Columns, Plates & Trusses in Section 2.7 of Exhibit A of the Application.

RAI 3.3-19 (11-19-98)
(Question refers to Section 3.3.1 of OLRP-1001)
In view of the fact that expansion joints, caulking, and sealants associated with containment structure integrity (e.g. moisture barrier at the junction of liner plate and basemat fill concrete) are not subjected to replacement based on qualified life or specified time period, explain why they should not be considered for aging management review [see 10 CFR 54.21(a)(1)(ii)] and addressed in this Section.

Response to RAI 3.3-19
The moisture barrier at the junction of the liner plate and basemat fill concrete is considered by Duke Energy to be a consumable, which is not expected to last 40 years and is replaced based on condition. As explained in detail in the Introduction to Attachment 4, Section III.f.(i)(b) of the SOC to 10 CFR Part 54 allows an applicant to determine that the replacement of a structure or component based on performance or condition provides reasonable assurance that the intended function of the passive structure of component will be maintained in the period of extended operation. The *Containment Inservice Inspection Plan* determines the replacement of the moisture barrier.

The condition of the moisture barrier at the interface of the liner plate and basemat concrete is assessed by the ASME Section XI Subsection IWE inspection which is discussed as part of the *Containment Inservice Inspection Plan* in Section 4.8 of Exhibit A of the Application. Examination Category E-D is identified in Table IWE-2500-1 for examination of the moisture barrier. The acceptance standards are identified in IWE-3513. For the moisture barrier, the programmatic action is not to "manage" the moisture barrier life, but rather to replace the moisture barrier when its condition indicates it is no longer acceptable for service. Therefore, the moisture barrier is replaced based on condition monitoring and, thus, is not subject to aging management review.

RAI 3.7.1-1 (11-18-98A)
In view of the fact that expansion joints, caulking, and sealants (other than those for fire barrier) are not subjected to replacement based on qualified life or specified time period, explain why they should not be considered for aging management review [see 10 CFR 54.21(a)(1)(ii)] and addressed in Sections 2.7 and 3.7.

Response to RAI 3.7.1-1
Expansion joints, caulking and sealants are considered by Duke Energy to be consumables. As explained in detail in the Introduction to Attachment 4, Section III.f.(i)(b) of the SOC to 10 CFR Part 54 allows an applicant to determine that the replacement of a structure or component based on performance or condition provides reasonable assurance that the intended function of the passive structure of component will be maintained in the period of extended operation. The *Inspection Program for Civil Engineering Structures and Components* determines the replacement of expansion joints, caulking and sealants.

Expansion joints, caulking, and sealants are routinely examined by inspections performed under the *Inspection Program for Civil Engineering Structures and Components.* This program is described in Section 4.19 of Exhibit A of the Application. Specific inspection methods, frequency and acceptance criteria are provided within this program. Expansion joints, caulking and sealant life is based on identification of wear or damage during this inspection. For expansion joints, caulking, and sealants, the programmatic action is not to "manage" their life, but rather to replace the expansion joints, caulking, and sealants when their condition indicates they are no longer acceptable for service. Therefore, expansion joints, caulking, and sealants are replaced based on condition monitoring and, thus, are not subject to aging management review.

RAI 3.7.3-4 (11-30-98A)
The caulking and sealants used for fire doors and fire walls as well as seals for penetrations are subject to aging related degradation. Discuss the aging effects on these items and how any aging effects on items in the Auxiliary Building will be managed to ensure performance of their intended safety functions during the period of extended operation.

Response to RAI 3.7.3-4
Caulking and sealants used for fire doors, fire walls, and fire barrier penetration seals installed in the Auxiliary Building are considered by Duke Energy to be consumables. As explained in detail in the Introduction to Attachment 4, Section III.f.(i)(b) of the SOC to 10 CFR Part 54 allows an applicant to determine that the replacement of a structure or component based on performance or condition provides reasonable assurance that the intended function of the passive structure of component will be maintained in the period of extended operation. The *Fire Protection Program* determines the replacement of the fire barrier caulking and sealants.

For the Auxiliary Building, the aging effects for fire barriers are discussed in Section 3.7.3.4 of Exhibit A of the Application. The applicable aging effects for caulking and sealants used in fire doors, fire walls, and fire barrier penetration seals will be managed by the *Fire Protection Program* that is discussed in Section 4.16 of Exhibit A of the Application. Specific inspection methods, frequency and acceptance criteria are provided within this program. Caulking and sealant life is based on identification of wear or damage during this inspection. For caulking and sealants used in fire doors, fire walls, and fire barrier penetration seals, the programmatic action is not to "manage" the caulking or seal life, but rather to replace them when their condition indicates they are no longer acceptable for service. Therefore, caulking and sealants used for fire doors, fire walls, and fire barrier penetration seals installed in the Auxiliary Building are replaced based on condition monitoring and, thus, are not subject to aging management review.

RAI 3.7.3-8 (11-30-98A)

Were sealants and caulking used for some of the flood, pressure and specialty doors (non fire-barrier items) of Auxiliary Building? If yes, discuss the basis for not listing degradation of these caulking and sealant materials as one of the aging effects in Table 3.7-1 of Oconee LRA, and indicate Oconee's plan to manage the degradation of these items.

Response to RAI 3.7.3-8

Sealants and caulking are used on some of the flood, pressure, and specialty doors in the Auxiliary Building. Sealants and caulking are considered by Duke Energy to be consumables. As explained in detail in the Introduction to Attachment 4, Section III.f.(i)(b) of the SOC to 10 CFR Part 54 allows an applicant to determine that the replacement of a structure or component based on performance or condition provides reasonable assurance that the intended function of the passive structure of component will be maintained in the period of extended operation. The *Inspection Program for Civil Engineering Structures and Components* determines the replacement of sealants and caulking.

Sealants and caulking are routinely examined by inspections performed under the *Inspection Program for Civil Engineering Structures and Components*. This program is described in Section 4.19 of Exhibit A of the Application. Specific inspection methods, frequency and acceptance criteria are provided within this program. Sealant and caulking life is based on identification of wear or damage during this inspection. For sealants and caulking in the Auxiliary Building, the programmatic action is not to "manage" their life, but rather to replace them when their condition indicates they are no longer acceptable for service. Therefore, sealants and caulking installed in the Auxiliary Building are replaced based on condition monitoring and, thus, are not subject to aging management review.

RAI 3.7.5-2 (11-18-98A)
Provide a summary of results (observations, identified degradations, corrective actions taken) of the Intake Structure baseline inspection (see also RAI 3.8.3.3) performed in accordance with Section 4.19. Also provide the results of the inspection related to the condition of caulking, seals, and expansion joints in the Intake Structure.

Response to RAI 3.7.5-2
Section 4.19 of Exhibit A of the Application addresses the *Inspection Program for Civil Engineering Structures and Components*. This program is credited with managing the aging effects of the Intake Structure.

During the most recent inspection in 1998, the Intake Structure was found to be in a structurally sound condition with no problems evident that would impede the structure's ability to perform any of its intended functions. Some conditions and degradations were noted that required corrective actions while others required continued surveillance during future inspections. Items requiring corrective actions will be resolved by Oconee Nuclear Station's PIP Process.

The inspection of the Intake Structure above water level was performed by professional engineers in Oconee Nuclear Station's engineering group. The underwater inspection was performed by divers from EASON Diving Company. The method of inspection was in accordance with the program discussed in Section 4.19 of Exhibit A of the Application, *Inspection Program for Civil Engineering Structures and Components*. Items from the previous inspection report were reviewed in the field to ensure that corrective actions had been completed where identified and to determine the extent of change in any areas that were to be monitored.

The inspection identified minor loss of material of steel components and concrete components. No degradation was noted for caulking, seals, or expansion joints. Corrective actions include cleaning and recoating of steel components, repair of concrete components, and continued monitoring in some areas.

Now, with respect to the results of the inspection related to the condition of caulking, seals, and expansion joints in the Intake Structure, caulking, seals, and expansion joints are considered by Duke Energy to be consumables. As explained in detail in the Introduction to Attachment 4, Section III.f.(i)(b) of the SOC to 10 CFR Part 54 allows an applicant to determine that the replacement of a structure or component based on performance or condition provides reasonable assurance that the intended function of the passive structure of component will be maintained in the period of extended operation. The *Inspection Program*

for Civil Engineering Structures and Components determines the replacement of caulking, seals, and expansion joints.

Caulking, seals, and expansion joints are routinely examined under the *Inspection Program for Civil Engineering Structures and Components.* This program is described in Section 4.19 of Exhibit A of the Application. Specific inspection methods, frequency and acceptance criteria are provided within this program. Caulking, seal, and expansion joint life is based on identification of wear or damage during this inspection. For caulking, seals, and expansion joints, the programmatic action is not to "manage" their life, but rather to replace them when their condition indicates they are no longer acceptable for service. Therefore, caulking, sealants, and expansion joints installed in the Intake Structure are replaced based on condition monitoring and, thus, are not subject to aging management review.

RAI 3.7.6-3 (11-30-98A)
Based on your past operating experience, indicate if the roof slabs of the Keowee Structure experienced any concrete cracking. If yes, discuss your plan for managing the aging effects resulting from structural steel and rebar corrosion that are embedded in the concrete slab due to accumulation and ingress of water through concrete cracks. Additionally, is there any concrete grout used for the Keowee Structure that is exposed to outside environment? If yes, discuss the potential of the grout being eroded or degraded due to sustained "freeze-thaw" as well as other weathering effects, and as applicable, discuss Oconee's approach for managing the effects of aging on concrete grout.

Response to RAI 3.7.6-3
Keowee Structures do not have any concrete roof slabs. Table 3.7-4 is misleading in that it lists roof slabs. Roof slabs were included in the general category with other reinforced concrete components. The Keowee Structures have a built-up roofing system.

Now, with respect to aging management of concrete grout in Keowee Structures, grout is considered by Duke Energy to be a consumable. As explained in detail in the Introduction to Attachment 4, Section III.f.(i)(b) of the SOC to 10 CFR Part 54 allows an applicant to determine that the replacement of a structure or component based on performance or condition provides reasonable assurance that the intended function of the passive structure of component will be maintained in the period of extended operation. The *Inspection Program for Civil Engineering Structures and Components* determines the replacement of grout.

Grout is routinely examined by inspections performed under *the Inspection Program for Civil Engineering Structures and Components.* This program is described in Section 4.19 of Exhibit A of the Application. Specific inspection methods, frequency and acceptance criteria are provided within this program. Concrete grout life is based on identification of wear or damage during this inspection. For concrete grout, the programmatic action is not to "manage" the grout life, but rather to replace the grout when its condition indicates it is no longer acceptable for service. Therefore, grout installed in Keowee Structures is replaced based on condition monitoring and, thus, is not subject to aging management review.

RAI 3.7.6-6 (11-30-98A)
Were sealants and caulking used for some of the flood, pressure and specialty doors (non fire-barrier items) of the Keowee Structure? If yes, discuss the basis for not listing degradation of these caulking and sealant materials as one of the aging effects in Table 3.7-4 of Oconee LRA, and indicate Oconee's plan to manage the degradation of these items.

Response to RAI 3.7.6-6
Sealants and caulking are used for some of the flood, pressure and specialty doors (non fire-barrier items) of the Keowee Structures. Sealants and caulking installed in structures are considered by Duke Energy to be consumables As explained in detail in the Introduction to Attachment 4, Section III.f.(i)(b) of the SOC to 10 CFR Part 54 allows an applicant to determine that the replacement of a structure or component based on performance or condition provides reasonable assurance that the intended function of the passive structure of component will be maintained in the period of extended operation. The *Inspection Program for Civil Engineering Structures and Components* determines the replacement of sealants and caulking in Keowee Structures.

Sealants and caulking are routinely examined by inspections performed under the *Inspection Program for Civil Engineering Structures and Components.* This program is described in Section 4.19 of Exhibit A of the Application. Specific inspection methods, frequency and acceptance criteria are provided within this program. Sealant and caulking life is based on identification of wear or damage during this inspection. For sealant and caulking, the programmatic action is not to "manage" their life, but rather to replace them when their condition indicates they are no longer acceptable for service. Therefore, sealants and caulking installed in Keowee Structures are replaced based on condition monitoring and, thus, are not subject to aging management review.

Set # 04
February 17, 1999

RAI 3.7.7-3 (11-30-98A)
The caulking and sealants used for flood, pressure and specialty doors as well as seals for penetrations are subject to aging related degradation due to the high temperature, humidity and radiation environment they are exposed to. Discuss the aging effects on these items and how any aging effects of items placed within the Reactor Building will be managed to ensure performance of their intended safety functions during the period of extended operation.

Response to RAI 3.7.7-3
Caulking and sealants used for doors installed in the Reactor Building are considered by Duke Energy to be consumables. Reactor Building Containment penetrations are addressed in Sections 2.3 and 3.3 of Exhibit A of the Application. Reactor Building Containment penetrations are constructed of welded steel members and do not contain seal material. As explained in detail in the Introduction to Attachment 4, Section III.f.(i)(b) of the SOC to 10 CFR Part 54 allows an applicant to determine that the replacement of a structure or component based on performance or condition provides reasonable assurance that the intended function of the passive structure of component will be maintained in the period of extended operation. The *Inspection Program for Civil Engineering Structures and Components* determines the replacement of caulking and sealants.

Caulking and sealants used for doors in the Reactor Building are routinely examined by inspections performed under the *Inspection Program for Civil Engineering Structures and Components*. This program is described in Section 4.19 of Exhibit A of the Application. Specific inspection methods, frequency and acceptance criteria are provided within this program. Caulking and sealant life is based on identification of wear or damage during this inspection. For caulking and sealants, the programmatic action is not to "manage" their life, but rather to replace them when their condition indicates they are no longer acceptable for service. Therefore, caulking and sealants used for flood, pressure and specialty doors in the Reactor Building are replaced based on condition monitoring and, thus, are not subject to aging management review.

RAI 3.7.9-2 (11-13-98)
Caulking and sealants that are not fire barriers and are exposed to ambient conditions are susceptible to degradation due to weathering. Your submittal did not address degradation of caulking and sealant. Provide a discussion of aging degradation of caulking and sealants (that are not fire barriers) and an aging management program that will address any degradation.

Response to RAI 3.7.9-2
Caulking and sealants installed in the Turbine Building are considered by Duke Energy to be consumables. As explained in detail in the Introduction to Attachment 4, Section III.f.(i)(b) of the SOC to 10 CFR Part 54 allows an applicant to determine that the replacement of a structure or component based on performance or condition provides reasonable assurance that the intended function of the passive structure of component will be maintained in the period of extended operation. The *Inspection Program for Civil Engineering Structures and Components* determines the replacement of caulking and sealants (that are not fire barriers).

Caulking and sealants are routinely examined by inspections performed under the *Inspection Program for Civil Engineering Structures and Components*. This program is described in Section 4.19 of Exhibit A of the Application. Specific inspection methods, frequency and acceptance criteria are provided within this program. Caulking and sealant life is based on identification of wear or damage during this inspection. For caulking and sealants, the programmatic action is not to "manage" their life, but rather to replace the caulking and sealant when its condition indicates it is no longer acceptable for service. Therefore, caulking and sealants installed in the Turbine Building are replaced based on condition monitoring and, thus, are not subject to aging management review.

ATTACHMENT 5
Oconee Nuclear Station
Application for Renewed Operating Licenses
Responses to NRC Requests for Additional Information (RAI)

Inaccessible Areas

Note: RAIs G-3 and G-5 are identical

RAI G-3 (11/18/98D)
Are there any parts of the systems, structures and components that are inaccessible for inspection? If so, describe what aging management program will be relied upon to maintain the integrity of the inaccessible areas. If the aging management program for the inaccessible areas is an evaluation of the acceptability of inaccessible areas based on conditions found in surrounding accessible areas, please provide information to show that conditions would exist in accessible areas that would indicate the presence of, or result in degradation to such inaccessible areas. If different aging effects or aging management techniques are needed for the inaccessible areas, please provide a summary to address the following elements for the inaccessible areas: (a) Preventive actions that will mitigate or prevent aging degradation; (b) Parameters monitored or inspected relative to degradation of specific structure and component intended functions; (c) Detection of aging effects before loss of structure and component intended functions; (d) Monitoring, trending, inspection, testing frequency, and sample size to ensure timely detection of aging effects and corrective actions; (e) Acceptance criteria to ensure structure and component intended functions; and (f) Operating experience that provides objective evidence to demonstrate that the effects of aging will be adequately managed.

RAI G-5 (12/3/98A)
Are there any parts of the systems, structures and components that are inaccessible for inspection? If so, describe what aging management program will be relied upon to maintain the integrity of the inaccessible areas. If the aging management program for the inaccessible areas is an evaluation of the acceptability of inaccessible areas based on conditions found in surrounding accessible areas, please provide information to show that conditions would exist in accessible areas that would indicate the presence of, or result in degradation to such inaccessible areas. If different aging effects or aging management techniques are needed for the inaccessible areas, please provide a summary to address the following elements for the inaccessible areas: (a) Preventive actions that will mitigate or prevent aging degradation; (b) Parameters monitored or inspected relative to degradation of specific structure and component intended functions; (c) Detection of aging effects before loss of structure and component intended functions; (d) Monitoring, trending, inspection, testing frequency, and sample size to ensure timely detection of aging effects and corrective actions; (e) Acceptance criteria to ensure structure and component intended functions; and (f) Operating experience that provides objective evidence to demonstrate that the effects of aging will be adequately managed.

Response to RAI G-3 and RAI G-5
Portions of the Oconee structures and components within the scope of license renewal are located in areas that are inaccessible for inspection. A number of questions have been raised by the NRC concerning aging management of inaccessible structures and components. The key to understanding the response to these questions is to understand the thoroughness of the aging management review process. The Oconee aging management review process methodically:

- identifies environments for the structures and components subject to aging management review,
- evaluates the material-environment combination for the structures and components to determine applicable aging effects, and
- identifies the program that will manage the applicable aging effects.

The purpose of the aging management review is to "demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation." [Reference §54.21(a)(3)] The review includes several steps: (1) identifying the applicable aging effects for the structure or component; (2) identifying existing or new programs for managing the applicable aging effects; and (3) demonstrating that the program is effective in managing the aging effects so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. The location of a structure or a component is a factor in identifying the applicable aging effect(s) and in determining the programmatic oversight.

The aging effects for a structure or component occur due to a combination of several physical parameters. The materials of construction, the environment to which the structure or component is exposed and the stress or load experienced by the structure or component all play a role in the determination of applicable aging effects. Structures and components that are inaccessible for inspection may be exposed to unique environments because of their location. The condition of the inaccessible structure or component can be established by identifying the environment and determining if subjecting the structure or component to the environment results in aging effects that could degrade the condition of the component. The inaccessible environment is evaluated as part of the aging management review to determine if structures and components that are located in this environment will have applicable aging effects.

The Oconee aging management review did not ignore any environmental conditions to which the structures and components are exposed, including those conditions in areas that may turn out to be inaccessible for inspection. For example, structures and components

located below grade may be exposed to groundwater. The groundwater environment could potentially lead to aging effects different from those in an air environment. The groundwater chemistry plays a major role in the determination of the degradation of below grade structures and components. When determining the applicable aging effects for below grade structures and components, the groundwater chemistry was evaluated to determine if parameters exceeded documented limits where degradation would occur. Therefore, the unique environment (groundwater) of the inaccessible structure or component was considered as part of the aging management review. In many instances, the proper selection of materials for the inaccessible environment results in few, if any, applicable aging effects.

The aging management review may determine that the environmental differences based on the location (such as concrete above grade exposed to air versus concrete below grade exposed to groundwater) do not result in unique aging effects for the inaccessible structure or component. Where the conditions in the inaccessible and accessible areas result in the same aging effects, the aging management program of the inaccessible area may be based on symptomatic evidence in an accessible area. For example, the aging effect due to alkali-aggregate reactions of concrete would manifest in both accessible and inaccessible areas.

For the case where symptomatic evidence in accessible areas provides guidance for aging effects in inaccessible areas, the aging management review assures that the aging effects due to the environment in the accessible region and the aging effects due to the environment in the inaccessible region are simultaneously evaluated. This philosophy forms the successful basis for the ASME Section XI oversight used to programmatically deal with inaccessible locations that require assurance of integrity. Programs such as the *Containment Inservice Inspection Plan* (Section 4.8), the *Inservice Inspection Plan* (Section 4.18) and the *Inspection Program for Civil Engineering Structures and Components* (Section 4.19) identified in Exhibit A of the Application use this philosophy.

When different aging effects due to environmental differences such as a more aggressive environment in the inaccessible area exist, other aging management approaches are needed. The guiding principle for the aging management review of these inaccessible areas is the knowledge of the environmental differences, such as more aggressive external environments due to the chemical composition of groundwater. The controlling or more aggressive location provides a "signal location" where the aging effects are more likely to be accelerated. These differences limit the intrusive nature of programmatic examination to the controlling or more aggressive location, i.e. "signal location." For those signal locations, a number of options exist in order to define program attributes that will assure that the structure or component intended function is maintained. These options may include, but are not limited to, remote examination techniques, disassembly, or excavation. The Oconee aging management review did not identify any inaccessible environments that result in aging

effects different from those in the accessible environments. No unique aging management programs were required for any inaccessible areas.

For uncertainties associated with inaccessible areas to be an issue, the aging management review process would have to disregard unique conditions to which the structures and components may be exposed. The process would have to lack the rigor of systematically evaluating the varying combinations of materials, environments, and stressors. The Oconee aging management review process did not disregard any environmental conditions to which the structures and components are exposed. Since the aging management review process considered the full range of environments to which each of the structures and components are exposed, then all applicable aging effects, including those caused by environmental conditions that may be associated with an inaccessible area, were identified. By methodically following the aging management review process, any aging effects that may occur due to the environment of the inaccessible area have been evaluated.

The programs relied upon to manage the applicable aging effects for the Oconee structures and components within the scope of license renewal are identified in Section 3 and described in Section 4 of Exhibit A of the Application. Program attributes such as items (a) through (f) in RAI G-3 were defined for each credited program and activity. Also, see Duke responses to RAIs 3.3-21, 3.4.11-4, 3.5.8-7, 3.7.3-7, 3.7.5-3, 3.7.6-5, 3.7.7-5, and 4.18-2 that address inaccessible structures and components and associated aging management programs.

RAI 3.3-21 (11-19-98)
In response to RAI 3.3-1 (Attachment 2 to Duke's letter to NRC on containment review for renewed operating license, August 12, 1998) you state that Section 3.3.2.7 has been revised to address inaccessible areas of containment concrete components. Your OLRP-1001, Section 3.3.2.6 indicates one sentence related to symptomatic evidence of cracking and leaching. Provide an explanation for why the below ground areas of concrete surfaces and embedded areas of liner plate (the inaccessible areas) should not be explicitly considered for aging management review based on the evidence cited in Sections 3.3.2.6 and 3.3.3.6.

Response to RAI 3.3-21
Below grade areas of concrete and embedded areas of the liner plate are inaccessible for inspection. As explained in detail in the response to RAI G-3, the aging management review process assured that program attributes were defined to manage all applicable aging effects for the structures and components within the scope of license renewal. Any applicable aging effect that was a result of environmental conditions in an area that is inaccessible for programmatic oversight was addressed during the definition of these program attributes.

Section 3.3.2.6 of Exhibit A of the Application provided Oconee operating experience that identified minor cracking and minor leaching in accessible areas of the Containment concrete. In light of these effects, additional consideration was given in the aging management review to concrete aging in inaccessible areas. By considering of the design, fabrication and operating environments including the aggressiveness of the groundwater, the inaccessible areas were determined to be no more susceptible to cracking and leaching than the accessible areas. The symptomatic evidence available from the existing plant structural surveillance programs will provide reasonable assurance that concrete cracking in inaccessible areas continued to be managed for the extended period of operation.

Section 3.3.3.6 of Exhibit A of the Application provided Oconee operating experience that identified loss of material due to corrosion of the liner plate below the concrete floor. The loss of material of the liner plate resulted from water intrusion through a degraded expansion joint sealant or moisture barrier. Under normal circumstances, the alkaline environment of the concrete floor would protect the concrete, but the environment was changed due to the introduction of water. Section 3.3.3.7 of the Application identifies loss of material as an applicable aging effect for the liner below the concrete floor if the expansion joint sealants are not maintained. The *Containment Inservice Inspection Plan* is credited with managing loss of material of the liner plate. The condition of the moisture barrier at the interface of the liner plate and basemat concrete is assessed by the ASME Section XI Subsection IWE Inspection which is part of the *Containment Inservice Inspection Plan*. The ASME Section XI Subsection IWE Inspection is discussed in Section 4.8 of Exhibit A of the Application. Examination Category E-D is identified in Table IWE-2500-1 for examination

of the moisture barriers. The acceptance standards are identified in IWE-3513. The identified degradation of the moisture barrier provided symptomatic evidence that degradation of the liner plate may exist. This symptomatic evidence lead to the construction of portals to perform examinations of the liner plate below the concrete. Non-destructive examinations of the liner plate were performed and it was determined that the extent of corrosion of the liner plate was negligible, and much less than 10% of the nominal wall thickness as allowed by IWE-3512. Based on this evidence, the *Containment Inservice Inspection Plan* provides reasonable assurance that aging effects for the inaccessible portions of the liner plate can be managed by symptomatic evidence in accessible areas so that the liner plate will continue to perform its intended function consistent with the current licensing basis for the period of extended operation.

RAI 3.5.8-7 (11/20/98B)
Are there any parts of the systems and attached devices within the HVAC systems that are inaccessible for inspection? If yes, provide a description in the application of how the potential aging effects will be identified and what aging management program (or programs) will be relied on to maintain the integrity of the inaccessible parts of the HVAC systems. If the aging management program for the inaccessible areas is an evaluation of the acceptability of inaccessible areas based on conditions found in surrounding accessible areas, please provide information to show that conditions would exist in accessible areas that would indicate the presence of or result in degradation to such inaccessible areas. If different aging effects or aging management techniques are needed for the inaccessible areas, please provide a summary to address the following elements for the 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 structure and component intended functions. (6) Operating experience that provides objective evidence to demonstrate that the effects of aging will be adequately managed.

Response to RAI 3.5.8-7
The Oconee HVAC systems within the scope of license renewal are Auxiliary Building Ventilation System, Control Room Pressurization and Filtration System, and Penetration Room Ventilation System. Some internal portions of these HVAC systems are inaccessible for inspection. As explained in detail in the response to RAI G-3, the Oconee aging management review process assured that program attributes were defined to manage all applicable aging effects for the structures and components within the scope of license renewal. Any applicable aging effect that was a result of environmental conditions in an area that is inaccessible for programmatic oversight was addressed during the definition of these program attributes.

Some of the internal surfaces of the Auxiliary Building Ventilation System, Control Room Pressurization and Filtration System, and Penetration Room Ventilation System are physically inaccessible for inspection. Accessibility is a concern only when applicable aging effects exists that require management. For the internal surfaces of the components within the scope of license renewal, no applicable aging effects are identified for the Auxiliary Building Ventilation System, Control Room Pressurization and Filtration System, and Penetration Room Ventilation System as noted in Section 3.5.8 and Table 3.5-6 of Exhibit A of the Application.

No external surfaces of the Auxiliary Building Ventilation system, Control Room Pressurization and Filtration System, and Penetration Room Ventilation System are inaccessible for inspection. For the external surfaces of these components, the applicable aging effect is loss of material due to boric acid wastage in all three systems and general corrosion in the Control Room Pressurization and Filtration and Penetration Room Ventilation Systems as noted in Section 3.5.2.7 of the Application. Loss of material due to boric acid wastage is managed by the *Boric Acid Wastage Surveillance Program* describe in Section 4.5 of the Application. *The Inspection Program for Civil Engineering Structures and Components* described in Section 4.19 of the Application manages loss of material due to general corrosion.

RAI 3.7.3-7 (11-30-98A)
Regarding the Inspection Program for Civil Engineering Structures and Components mentioned in Sections 3.7.3.1 and 3.7.3.2, provide the following information:

(a) Are there any parts of the Auxiliary Building structures and components that are inaccessible for inspection? If so, describe, how the Inspection Program for Civil Engineering Structures and Components will be relied upon to maintain the integrity of the inaccessible areas. Include an example of how the program specifically addressed an inaccessible area. If the aging management program for the inaccessible areas is an evaluation of the acceptability of inaccessible areas based on conditions found in surrounding accessible areas, please provide information to show that conditions would exist in accessible areas that would indicate the presence of or result in degradation to such inaccessible areas. If different aging effects or aging management techniques are needed for the inaccessible areas, please provide a summary to address the following elements for the 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 structure and component intended functions, and (6) operating experience that provides objective evidence to demonstrate that the effects of aging will be adequately managed.

(b) The program stated that the nominal frequency of inspection was once every five years with an option of decreasing the frequency to a once every ten-year inspection with appropriate justification. Discuss some examples of justifications which will be appropriate for extending the five-year inspection interval to 10 years. Industry standards generally call for a six-year inspection frequency.

Response to RAI 3.7.3-7
(a) Parts of the Auxiliary Building structures and components are inaccessible for inspection. As explained in detail in the response to RAI G-3, the Oconee aging management review process assured that program attributes were defined to manage all applicable aging effects for the structures and components within the scope of license renewal. Any applicable aging effect that was a result of environmental conditions in an area that is inaccessible for programmatic oversight was addressed during the definition of these program attributes.

Examples of Auxiliary Building structures and components that are inaccessible for inspection are below grade components and the underside of steel base plates. For the

foundation and other below grade components such as reinforced concrete walls, no applicable aging effects were identified in Table 3.7-1 of Exhibit A of the Application. Section 3.7.2 of the Application and the Duke response to RAI 3.7.3-2 provide more information on the applicable aging effects of below grade concrete.

Loss of material due to corrosion was identified as an applicable aging effect in Table 3.7-1 for steel plates including the underside of steel base plates. Loss of material on the underside of the base plate is not due to any unique environment associated with the inaccessible area. The underside of the base plate is subjected to the same environmental conditions as are present on the accessible side. The *Inspection Program for Civil Engineering Structures and Components* is credited with managing loss of material of steel plates. The *Inspection Program for Civil Engineering Structures and Components* performs a visual examination to identify any corrosion of steel plates. The visual examination would identify symptomatic evidence of corrosion on the underside of the base plate. The symptomatic evidence may include corrosion on the accessible side, which is exposed to the same environment as the inaccessible side, or streaking on the wall due to corrosion on the underside of the plate. The *Inspection Program for Civil Engineering Structures and Components* is discussed in more detail in Section 4.19.

(b) Section 4.19 of Exhibit A of the Application describes *the Inspection Program for Civil Engineering Structures and Components*. The inspection will be performed nominally every five years, with the exact schedule being established with consideration of refueling outages of each Oconee unit. The interval may be increased to a nominal ten-year frequency with appropriate justification based on the structure, environment, and related inspection results. For example, the inspection frequency of a non-safety structure which could impact a safety-related structure, but which is subjected to a benign environment and has not experienced any degradation over several decades of operation which could impact the ability of the structure to perform its intended function, may be extended to 10 years in accordance with industry standards. Technical justification would be established by engineering for any decrease in the frequency of inspections.

The statement that industry standards generally call for a six year inspection frequency is unclear. Industry standards generally call for a five to ten year inspection frequency. The following are several examples, applicable to Oconee, that illustrate this general inspection frequency. ASME Section XI Subsections IWE and IWL inspections of Reactor Building components are performed on a five year frequency. NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*, provides guidance on the inspection frequency of tanks, which is on five year

intervals. NUREG-1522, *Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures*, suggest periodic inspection of safety-related structures every five to ten years depending on the structure, environment, and age. Regulatory Guide 1.127, *Inspection of Water-Control Structures Associated with Nuclear Power Plants*, provides general guidance on inspections with frequencies not to exceed five years. Regulatory Guide 1.160, *Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*, states that the appropriate frequency of the assessments would be commensurate with the safety significance of the structure and its condition.

RAI 3.7.5-3 (11-18-98A)
Are there any parts of the intake structure that are inaccessible for inspection? If so, describe what aging management program will be relied upon to maintain the integrity of the inaccessible areas. If the aging management program for the inaccessible areas is an evaluation of the acceptability of inaccessible areas based on conditions found in surrounding accessible areas, please provide information to show that conditions would exist in accessible areas that would indicate the presence of or result in degradation to such inaccessible areas. If different aging effects or aging management techniques are needed for the inaccessible areas, please provide a summary to address the following elements for the 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 structure and component intended functions. (6) Operating experience that provides objective evidence to demonstrate that the effects of aging will be adequately managed.

Response to RAI 3.7.5-3
Parts of the Intake Structure are inaccessible for inspection. As explained in detail in the response to RAI G-3, the Oconee aging management review process assured that program attributes were defined to manage all applicable aging effects for the structures and components within the scope of license renewal. Any applicable aging effect that was a result of environmental conditions in an area that is inaccessible for programmatic oversight was addressed during the definition of these program attributes.

Examples of Intake Structure components that are inaccessible for inspection are underwater concrete components and the underside of steel base plates. For the concrete foundation, no applicable aging effects were identified in Table 3.7-3 of Exhibit A of the Application. Other reinforced concrete components such as walls are subjected to flowing water that may result in loss of material. Table 3.7-3 identifies loss of material as an applicable aging effect for the reinforced concrete walls. Section 3.7.2 of the Application provides more information on the applicable aging effects of concrete located in Lake Keowee. The *Inspection Program for Civil Engineering Structures and Components* is credited with managing loss of material of concrete components. An underwater inspection of the Intake Structure is performed as part of the *Inspection Program for Civil Engineering Structures and Components*. The *Inspection Program for Civil Engineering Structures and Components* performs a visual examination to identify loss of material.

Loss of material due to corrosion was identified as an applicable aging effect in Table 3.7-3 for steel plates including the underside of steel base plates. Loss of material on the underside of the base plate is not due to any unique environment associated with the inaccessible area. The underside of the base plate is subjected to the same environmental conditions as are present on the accessible side. The *Inspection Program for Civil Engineering Structures and Components* is credited with managing loss of material of steel plates. The *Inspection Program for Civil Engineering Structures and Components* performs a visual examination to identify any corrosion of steel plates. The visual examination would identify symptomatic evidence of corrosion on the underside of the base plate. The symptomatic evidence may include corrosion on the accessible side which is exposed to the same environment as the inaccessible side or streaking on the wall due to corrosion on the underside of the plate. The *Inspection Program for Civil Engineering Structures and Components* is discussed in more detail in Section 4.19.

RAI 3.7.6-5 (11-30-98A)
Regarding the Inspection Program for Civil Engineering Structures and Components mentioned in Sections 3.7.6.1 and 3.7.6.2, provide the following information:

(a) Describe the criteria for judging that an inspected item needs corrective action(s) to ensure that it will perform its intended safety function. Also, provide a brief description of the ranges of potential corrective actions that might be implemented, on an as-needed basis, for the Keowee Structure and component supports.

(b) Are there any parts of the Keowee structures and components that are inaccessible for inspection, perhaps due to the presence of water? If so, describe, how the Inspection Program for Civil Engineering Structures and Components will be relied upon to maintain the integrity of the inaccessible areas. Include an example of how the program specifically addressed an inaccessible area. If the aging management program for the inaccessible areas is an evaluation of the acceptability of inaccessible areas based on conditions found in surrounding accessible areas, please provide information to show that conditions would exist in accessible areas that would indicate the presence of or result in degradation to such inaccessible areas. If different aging effects or aging management techniques are needed for the inaccessible areas, please provide a summary to address the following elements for the 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 structure and component intended functions, and (6) operating experience that provides objective evidence to demonstrate that the effects of aging will be adequately managed.

(c) Discuss why the nominal frequency of inspection for the Keowee Structure is not more frequent than that of the Auxiliary Building due to constant exposure to water and chemicals, such as chlorides or sulfides.

Response to RAI 3.7.6-5
(a) The *Inspection Program for Civil Engineering Structures and Components* is credited with managing aging in Section 3.7.6.1 and 3.7.6.2 of Exhibit A of the Application. Table 3.7-4 lists the components, the applicable aging effects, and the programs that will manage the effects. The acceptance criteria and corrective action are described in Section 4.19 of Exhibit A of the Application. The acceptance criteria for the program include no indication of loss of material, cracking or change of material properties for concrete and no loss of material for steel, which could lead to possible failure prior to the

next scheduled inspection, as identified by the accountable engineer. Components that do not meet the acceptance criteria are evaluated for continued service, monitored, repaired or replaced. Specific corrective actions will be implemented in accordance with the program guidance document.

(b) Parts of the Keowee Structure are inaccessible for inspection. As explained in detail in the response to RAI G-3, the Oconee aging management review process assured that program attributes were defined to manage all applicable aging effects for the structures and components within the scope of license renewal. Any applicable aging effect that was a result of environmental conditions in an area that is inaccessible for programmatic oversight was addressed during the definition of these program attributes.

Examples of Keowee Structure components that are inaccessible for inspection are underwater concrete components and the underside of steel base plates. For the concrete foundation, no applicable aging effects were identified in Table 3.7-3 of Exhibit A of the Application. Other reinforced concrete components in the Keowee Intake and Spillway are subjected to water that may result in loss of material and change in material properties. Table 3.7-3 identifies loss of material and change in material properties as applicable aging effects for the Keowee Intake concrete. Section 3.7.2 of the Application provides more information on the applicable aging effects of concrete located in Lake Keowee. The *Duke Power Five-Year Underwater Inspection of Hydroelectric Dams and Appurtenances* is credited with managing loss of material and change in material properties of Keowee Intake concrete components. The *Duke Power Five-Year Underwater Inspection of Hydroelectric Dams and Appurtenances* performs a visual examination to identify loss of material and change in material properties due to leaching. The *Duke Power Five-Year Underwater Inspection of Hydroelectric Dams and Appurtenances* is discussed in more detail in Section 4.12 of Exhibit A of the Application.

Loss of material due to corrosion was identified as an applicable aging effect in Table 3.7-4 for steel plates including the underside of steel base plates. Loss of material on the underside of the base plate is not due to any unique environment associated with the inaccessible area. The underside of the base plate is subjected to the same environmental conditions as are present on the accessible side. The *Inspection Program for Civil Engineering Structures and Components* is credited with managing loss of material of steel plates. The *Inspection Program for Civil Engineering Structures and Components* performs a visual examination to identify any corrosion of steel plates. The visual examination would identify symptomatic evidence of corrosion on the underside of the base plate. The symptomatic evidence may include corrosion on the accessible side, which is exposed to the same environment as the inaccessible side, or streaking on

the wall due to corrosion on the underside of the plate. The *Inspection Program for Civil Engineering Structures and Components* is discussed in more detail in Section 4.19.

(c) The frequency of inspection for the Auxiliary Building, Keowee Structures and all structures other than Reactor Building Containment is nominally every five years as discussed in Section 4.19 of Exhibit A of the Application. Although some components of Keowee Structures are exposed to lake water, the chemical concentrations of chlorides and sulfates (See response to RAI 3.7.5-1) do not exceed the limits where degradation would occur (See information in Section 3.7.2). Therefore, the Keowee Structures are not exposed to a more aggressive environment that would require more frequent inspections. Operating history supports this conclusion.

RAI 3.7.7-5 (11-30-98A)
Regarding the Inspection Program for Civil Engineering Structures and Components mentioned in Sections 3.7.7.1 and 3.7.7.2, provide the following information:

(a) Are there any parts of the Reactor Building structures and components that are inaccessible for walkdown inspection, due to high radioactive doses or temperatures? If so, describe, how the Inspection Program for Civil Engineering Structures and Components will be relied upon to maintain the integrity of the inaccessible areas. Include an example of how the program specifically addressed an inaccessible area. If the aging management program for the inaccessible areas is an evaluation of the acceptability of inaccessible areas based on conditions found in surrounding accessible areas, please provide information to show that conditions would exist in accessible areas that would indicate the presence of or result in degradation to such inaccessible areas. If different aging effects or aging management techniques are needed for the inaccessible areas, please provide a summary to address the following elements for the 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 structure and component intended functions, and (6) operating experience that provides objective evidence to demonstrate that the effects of aging will be adequately managed.

(b) The program stated that the nominal frequency of inspection was once every five years with an option of decreasing the frequency to a once every ten-year inspection with appropriate justification. With respect to items placed within the Reactor Building, provide a basis why doubling the duration between inspections can be justified.

Response to RAI 3.7.7-5
(a) Parts of the Reactor Building Internal Structural components are inaccessible for inspection due to high radiation or temperature. As explained in detail in the response to RAI G-3, the Oconee aging management review process assured that program attributes were defined to manage all applicable aging effects for the structures and components within the scope of license renewal. Any applicable aging effect that was a result of environmental conditions in an area that is inaccessible for programmatic oversight was addressed during the definition of these program attributes.

High radiation and high temperature service environments are discussed in Section 3.7.2.1.1 of Exhibit A of the Application. Aging effects resulting from high radiation or high temperature were evaluated for the Reactor Building Internal Structural components. The radiation and temperature in the Reactor Building do not exceed the threshold limits where degradation could occur (See Duke response to RAI 3.2-3 for additional information concerning the effects of radiation and temperature on structural components.). Therefore, the environment associated with the inaccessible area does not result in any different aging effects than those resulting from conditions in the accessible environment.

For example, loss of material of steel components is identified as an applicable aging effect in Table 3.7-5 of Exhibit A of the Application. Steel components may be located in an air environment that is inaccessible due to temperature and radiation. These components do not see any aging effects resulting from the temperature and radiation. Therefore, these components will have the same aging effects as accessible components in an air environment. Identification of aging effects for the accessible components provides symptomatic evidence of aging effects in inaccessible areas.

As a specific example of a steel component located in an inaccessible area, a piping system may travel from an accessible location into a high radiation area. Some of the pipe supports for the system are accessible for inspection and others are not accessible due to the radiation. Because the high radiation does not exceed the threshold levels where degradation would occur, the radiation does not result in any additional applicable aging effects beyond loss of material. Loss of material is identified as an applicable aging effect in Table 3.7-5 for pipe supports. The *Inspection Program for Civil Engineering Structures and Components* is one of the programs credited with managing loss of material for pipe supports. The *Inspection Program for Civil Engineering Structures and Components* uses visual examination to identify any loss of material due to corrosion. The visual examination of the accessible pipe supports provides symptomatic evidence of the condition of the pipe supports in the inaccessible region since they are both exposed to the air environment.

(b) Section 4.19 of Exhibit A of the Application discusses *the Inspection Program for Civil Engineering Structures and Components*. This program is credited with managing aging of several components within the Reactor Building in Table 3.7-5. This program does not address components that provide Containment functions. Components that provide Containment functions are addressed in Section 3.3 of Exhibit A of the Application and aging effects are managed by other programs, which are completed once every five years. The Inspection Program for Civil Engineering Structures and Components will nominally be performed every five years, with the exact schedule being established with

consideration of refueling outages of each Oconee unit. The interval may be increased to a nominal ten-year frequency with appropriate justification based on the structure, environment, and related inspection results. To determine that a 10-year frequency is appropriate for the Reactor Building Internal components, inspection results from previous inspections would need to validate that a less frequent inspection is appropriate and technical justification would be provided by engineering. Also, see response to RAI 3.7.3-7, which discusses inspection frequencies.

RAI 4.18-2 (12/2/98D)

Section 4.18 "Inservice Inspection Plan" as titled, is a subset of an overall inservice inspection plan applicable for management of aging in certain Class 1 components. Since the examinations under ASME Code, Section XI, are being credited towards detection of aging effects to maintain the intended function of the components during the period of extended operation, please provide the following information:

Are there components or structures within the inservice inspection boundary that are either inaccessible or cannot be examined in accordance with the applicable Code due to geometry and/or physical constraints? The section 4.18.1 "Scope" states that in instances of inaccessibility of components for examination, an indirect assurance of component integrity shall be made. How will this indirect assurance address aging effects in the component? If the aging management program for the inaccessible areas is an evaluation of the acceptability of inaccessible areas based on conditions found in surrounding accessible areas, please provide information to show that conditions would exist in accessible areas that would indicate the presence of, or result in degradation to, such inaccessible areas. Please provide a summary to address the following elements for the inaccessible areas:

(a) Preventive actions that will mitigate or prevent aging degradation;

(b) Parameters monitored or inspected relative to degradation of specific structures and component intended functions;

(c) Detection of aging effects before loss of structure and component intended functions;

(d) Monitoring, trending, inspection, testing frequency, and sample size to ensure timely detection of aging effects and corrective actions;

(e) Acceptance criteria to ensure structure and component intended functions; and

(f) Operating experience that provides objective evidence to demonstrate that the effects of aging will be adequately managed.

Response to RAI 4.18-2

The Oconee Inservice Inspection Plan is credited as one of the aging management programs for a number of the Class 1 components. None of these Class 1 components is inaccessible for examination under the current requirements of ASME Section XI. A review of the relief requests in the current Oconee Inservice Inspection Plan indicates only limited instances where a feature of a component, such as a weld, could not be examined to the extent required by the Code. As a point of clarification, the "items" referred to in the Section 4.18.1 "Scope" paragraph are not the components themselves, but are those component features that may not be found to be completely accessible and may require relief from the examination requirements. No feature of any of the Class 1 components under discussion here is located in a unique environment such that aging effects would manifest themselves in a manner that would not be managed by the ASME Section XI examination requirements.

ATTACHMENT 6

Oconee Nuclear Station

Application for Renewed Operating Licenses

Responses to NRC Requests for Additional Information (RAI)

Set # 04
February 17, 1999

RAI 2-1 (12/1/98B)
Various Oconee license renewal basis documents contained blocked "confirmation required" annotations. However, the staff was informed during a site visit from October 27 through 30, 1998, that there were no formal administrative control processes in place to track these items to resolution. [OLRP-1001 Section 2.0] Please describe the actions that have either been implemented or that Duke anticipates will be taken to resolve this issue dealing with QA-1 documentation.

Response to RAI 2-1
At the time that the technical bases documents were being completed to support the license renewal submittal, several issues existed that were external to the license renewal project. It was determined that resolution of these issues may have the potential to affect the technical documents that support the license renewal application material. A marker was placed in the technical documents to ensure that these issues, once resolved, are considered for impact to the license renewal technical documents. These issues are called "Open Items" in the documents. The open items have been entered into Oconee's Problem Investigation Process (PIP) to track resolution. Additional information about PIP is given in response to RAI 4.3.9-4. The PIP provides the administrative control to ensure that corrective actions are taken to resolve and close out the open issues within the technical documents.

It is Duke's intent to resolve the open items in these technical bases documents in preparation for the annual review and update of the application materials required by §54.21(b). The development and revision of the technical bases documents continue to be controlled by a project workplace procedure.

RAI G-1
Has Duke Energy committed to extending 10 CFR Part 50, Appendix B requirements for "corrective actions," "confirmation process," and "administrative controls" to cover non-safety-related structures and components subject to aging management review (AMR)? If not, what is Duke Power using to address these required elements of a program for non-safety related structures and components requiring an aging management review.

Response to RAI G-1
The NRC Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants (SRP-LR) provides two options for addressing corrective actions, including the confirmation process, and administrative controls of non-safety related structures and components within the scope of license renewal and subject to aging management review. One option is to include the non-safety related structures and components in the licensee's Appendix B to 10 CFR Part 50 Program. Duke does not intend

to extend the 10 CFR Part 50, Appendix B requirements to cover the aging management program elements for non-safety related structures and components subject to aging management review.

The second option provided in the SRP-LR is to include the non-safety related structures and components in a separate renewal program that is summarized in the FSAR Supplement. This second option will be implemented for Oconee. The program elements for corrective action, including confirmation, and administrative controls will be clarified for each program that addresses the aging effects on non-safety related structures and components within the scope of license renewal to assure these elements are properly addressed. These updated program elements will be summarized for the applicable programs in the Oconee UFSAR.

The following aging management programs include non-safety related structures and components within the scope of license renewal:

- *Cast Iron Selective Leaching Inspection*
- *Galvanic Susceptibility Inspection*
- *Keowee Air and Gas Systems Inspection*
- *Preventive Maintenance Activities (These activities were further defined in response to RAI 4.3.8-1. Some of these activities address aging of non-safety related structures and components.)*
- *Reactor Coolant Pump Motor Oil Collection System Inspection*
- *Treated Water System Stainless Steel Inspection*
- *Boric Acid Wastage Surveillance Program*
- *Chemistry Control Program*
- *Duke Power Five-Year Underwater Inspection of Hydroelectric Dams and Appurtenances*
- *Fire Water System Test*
- *Inspection Program for Civil Engineering Structures and Components*
- *Piping Erosion/Corrosion Program*
- *Service Water Piping Corrosion Program*
- *System Performance Testing Activities*
- *230 kV Keowee Transmission Line Inspection*

Set # 04
February 17, 1999

RAI 4.13-1

In OLRP-1001, Subsection 4.13, "Duke Quality Assurance Program," Duke states, in part, that it has "established and implemented a Quality Assurance Program which conforms to the criteria established in 10 CFR Part 50, Appendix B, 'Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.'" This subsection further states that "[t]he Quality Assurance Program is presented in the Duke Power Topical Report "Quality Assurance Program," DUKE-1A, which is incorporated by reference into Chapter 17 of the Oconee UFSAR. The Quality Assurance Program addresses all aspects of quality assurance at Duke's nuclear power stations." Subsection 4.13, also asserts that, "[t]wo of these aspects that are *pertinent to the aging management programs identified for license renewal* are "Corrective Actions" and "Document Control" which are briefly described below." Subsections 4.13.1 and 4.13.2 provide a limited description of the implementation aspects of Duke's corrective action and document control programs as they relate to safety-related structures, systems and components subject to an aging management program. However, the aging management program for Oconee includes both safety-related and nonsafety-related SSCs.

Please describe the methodology and processes that will be used by Duke to address corrective actions, confirmation processes and administrative controls for nonsafety-related SSCs subject to an aging management program at Oconee in a manner consistent with the guidance in draft "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR). If Duke has elected not to use the guidance in the draft SRP-LR, please provide justification.

Response to RAI 4.13-1

Please refer to the response to RAI G-1 for details concerning Duke's plans.

ATTACHMENT 7
Oconee Nuclear Station
Application for Renewed Operating Licenses
Responses to NRC Requests for Additional Information (RAI)

LIST OF COMMITMENTS

Attachment 7
Oconee Nuclear Station
Application for Renewed Operating Licenses
Responses to NRC Requests for Additional Information

Set # 04
February 17, 1999

LIST OF COMMITMENTS

Note: Commitments are docketed statements that establish requirements or actions to be performed.

1. Based on further review, commitment Number 1 provided in Duke letter dated February 8, 1999 (which provided Set #03) will be revised to the following:

   Exhibit A, Section 4.5, "Boric Acid Wastage Surveillance Program - Frequency" will be revised to state: "Inspections of the Reactor Building are performed each refueling outage. Inspections of the Auxiliary Building are performed at a minimum each time the Reactor Building is inspected."

2. Upon completion of the staff review of BAW-2251 and the issuance of the Safety Evaluation, Duke will update its responses to the BAW-2251 renewal applicant action items, as necessary.

3. The "Timing of New Program or Activity" statement provided on page 4.3.13 of Exhibit A of the Application will be revised to read:

   Timing of New Program or Activity – The *Keowee Oil Sampling Prog*ram is an existing program that will be continued into the extended period of extended operation. This program will be monitored for effectiveness via ongoing maintenance assessment activities at Oconee and enhancements will be made as determined by the assessments prior to February 6, 2013 (the end of the initial license term for Oconee Unit 1).

4. The requirement regarding modifications to design and operation that result in changes to neutron energy spectrum relative to that discussed in BAW-1543, Revision 4, will be added to Section 4.24.1 of Exhibit A of the Application within the attribute entitled "Acceptance Criteria or Standard."

5. The requirement regarding modifications to design and operation that result in changes to gamma heating relative to that discussed in BAW-1543, Revision 4, will be added to Section 4.24.1 of Exhibit A of the Application within the attribute entitled "Acceptance Criteria or Standard."

6. The requirement regarding modifications to design and operation that result in changes to reactor vessel inlet temperature neutron energy spectrum relative to that discussed in BAW-1543, Revision 4, will be added to Section 4.24.1 of Exhibit A of the Application within the attribute entitled "Acceptance Criteria or Standard."

LIST OF COMMITMENTS

7. The Oconee UFSAR Supplement will be revised to appropriately incorporate the staff safety evaluation of the leak-before-break analysis described in response to RAI 5.4.1-1.

8. The response to RAI 5.4.2-1 provides revised RT_{PTS} calculations for each Oconee Unit that supercede those provided in Section 5.4.2.1 of Exhibit A of the Application. All three Oconee Units meet the RT_{PTS} screening criteria contained in §50.61 through the period of extended operation. Section 5.4.2.1 of Exhibit A of the Application and the applicable section of the UFSAR Supplement will be revised to reflect these new results and to withdraw commitments that are no longer required.

9. The program elements for corrective action, including confirmation, and administrative controls will be clarified for each program that addresses the aging effects on non-safety related structures and components within the scope of license renewal to assure these elements are properly addressed. These updated program elements will be summarized for the applicable programs in the Oconee UFSAR. [RAI G-1]