FORT CALHOUN STATION, UNIT 1
LICENSE RENEWAL APPLICATION REVIEW
STAFF REQUESTS FOR ADDITIONAL INFORMATION (RAIs)

2.1 Scoping and Screening Methodology

2.1-1 10 CFR 54.4(a)(2) Scoping Criteria for Non-Safety-related SSCs

By letters dated December 3, 2001, and March 15, 2002, respectively, the Nuclear Regulatory Commission (NRC) issued a staff position to the Nuclear Energy Institute (NEI) which described areas to be considered, and options the NRC expects applicants for license renewal to use, to determine what systems, structures, or components (SSCs) meet the 10 CFR 54.4(a)(2) criterion (i.e., all non-safety-related SSCs whose failure could prevent satisfactory accomplishment of any safety-related functions identified in paragraphs (a)(1)(i),(ii),(iii) of this section).

The December 3, 2001, letter provided specific examples of operating experience which identified pipe failure events (summarized in Information Notice (IN) 2001-09, "Main Feedwater System Degradation in Safety-Related ASME Code Class 2 Piping Inside the Containment of a Pressurized Water Reactor") and the approaches the NRC considers acceptable to determine which piping systems should be included in scope based on the 54.4(a)(2) criterion.

The March 15, 2002, letter further described the staff's expectations for the evaluation of non-piping SSCs to determine which additional non-safety-related SSCs are within scope. The position states that applicants should not consider hypothetical failures, but rather should base their evaluation on the plant's CLB, engineering judgement and analyses, and relevant operating experience. The paper further describes operating experience as all documented plant-specific and industry-wide experience which can be used to determine the plausibility of a failure. Documentation would include NRC generic communications and event reports, plant-specific condition reports, industry reports such as SOERs, and engineering evaluations.

Consistent with the staff position described in the aforementioned letters, please describe your scoping methodology implemented for the evaluation of the 10 CFR 54.4(a)(2) criterion. As part of your response please indicate the option(s) credited, list the SSCs included within scope as a result of your efforts, list those structures and components (SCs) for which aging management reviews were conducted, and, for each SC, describe the aging management programs, as applicable, to be credited for managing the identified aging effects.

2.1-2 Quality Assurance Program Attributes in Appendix A, "Updated Safety Analysis Report (USAR) Supplement," and Appendix B, "Aging Management Activities"

During the audit of the FCS scoping and screening methodology, the staff reviewed the applicant's programs described in Appendix A, "Updated Safety Analysis Report (USAR) Supplement," and Appendix B, "Aging Management Activities" to assure that the aging management activities were consistent with the staff's guidance described in SRP-LR Section A.2, "Quality Assurance for Aging Management Programs" and Branch Technical Position IQMB-1, regarding quality assurance (QA) of the LR-SRP.

Based on the staff's evaluation, the descriptions and applicability of the aging management programs and their associated attributes to all safety-related and non-safety-related SCs provided in Appendix A and Appendix B of the LRA are consistent with the staff's position regarding quality assurance for aging management. However, the applicant has not sufficiently described the use of the quality assurance program and its associated attributes (corrective action, confirmation process, and document control) in the discussion provided. The staff requests that the applicant clarify their descriptions in the Appendix A, "Updated Safety Analysis Report (USAR) Supplement," and Appendix B, "Aging Management Activities" to include aspects of the quality assurance program which are credited for the three AMP attributes identified above.

2.1-3 Long-Term Implementation

During the audit of the FCS scoping and screening methodology, the audit team determined that the procedures reviewed, in combination with the review of a sample of scoping and screening products, provided adequate evidence that the scoping and screening process was conducted in accordance with the requirements of 10 CFR 54.4, "Scope," and 10 CFR 54.21, "Contents of Application — Technical Information." Additionally, the staff reviewed the applicant's draft position paper describing the potential long-term program implementation of the LRA methodology and guidance into the operational phase of the plant during the period of extended operation. As a result, the team concluded that the applicant needs to provide a description of the process it intends to implement to capture the scoping and screening process upon which the applicant will rely during the period of extended operation at FCS to satisfy the requirements of 10 CFR 54.35, "Requirements During the Term of Renewed License."

2.1.4 Pressurized Thermal Shock (PTS) and Anticipated Transient Without Scram (ATWS)

2.1.4-1 On page 2-9 of the LRA, it is stated that no additional equipment was included within the scope of license renewal due to the PTS Rule and all systems credited for ATWS mitigation are within the scope of license renewal for reasons other than ATWS mitigation. As written, the staff is concerned that all structures, systems, and components required to ensure compliance with the PTS Rule (10 CFR 50.61) and the ATWS Rule (10 CFR 50.62), are not identified in the LRA. Therefore, the staff requests that the applicant identify which SSCs are credited for meeting the requirements of 10 CFR 54.4a(3) for PTS and ATWS. This information is necessary in order for the staff to have reasonable assurance that all the SSCs have been correctly identified as being within scope and subject to an AMR in accordance with 10 CFR Part 54.

2.2 Plant-Level Scoping Results

2.2-1 A legend was not provided for the system drawings. A legend is needed to ensure that the staff can properly identify system components. Please provide such a legend.

2.2-2 For some of the systems highlighted on the system drawings, the license renewal boundaries appear to start/stop at the boundary between two design classes. Provide definitions of the design classes used at FCS and identify the classes which contain CQE components and Limited CQE components.

2.2-3 Title 10 CFR 54.37(b) requires that FSAR updates after the renewed license is issued must include any systems, structures, and components newly identified that would have been subject to an aging management review in accordance with 10 CFR 54.21. Describe how the drawings submitted as reference material for your application will be maintained and updated to reflect newly identified SSCs.

2.3.1.2 Reactor Coolant

2.3.1.2-1 The FCS CLB for FP complies with certain sections of Appendix R, particularly Section III.G, which provides the requirements for the fire protection safe shutdown capability. Discuss if the pressurizer spray head and associated piping are credited and relied upon in the fire protection safe shutdown analysis to bring the plant to cold shutdown conditions within a given time for compliance with Appendix R. If it is credited in the fire protection safe shutdown analysis, the pressurizer spray head and associated piping would satisfy 10 CFR 50.48, Appendix R requirements and, therefore, should be included within the scope of license renewal. The specific intended function of the subject components which meets the 10 CFR 54.4(a)(3) requirement is the spray function, and the particular components which help perform this function are the section of piping and the spray head located inside the pressurizer. The subject components do not have a pressure boundary function. The staff believes that with the loss of spray function, it may not be possible to bring the plant to cold shutdown conditions within a given time for compliance with Appendix R and, therefore, the spray head and associated piping inside pressurizer, and the spray function should be identified as within the scope of license renewal. Furthermore, the applicant should propose an AMP for the spray head and associated piping inside the pressurizer, which provides a reasonable assurance that adequate spray function will be maintained during the period of extended operation.

2.3.1.2-2 Pursuant to 10 CFR Part 50, App. R, Sec. III.O, the reactor coolant pump (RCP) lube oil collection subsystem is designed to collect oil from the RCPs and drain it to a collection tank to prevent a fire in the containment building during normal plant operations. The staff believes that the subsystem and the tank should be within the scope of license renewal and require aging management. However, it appears that the subject components were not identified in the LRA (Tables 2.3.1.2-1 or 2.3.3.14-1); and, therefore, the staff requests the applicant to provide an explanation.

2.3.1.2-3 Steam generators (SG) are generally equipped with flow restrictors, one of whose intended functions is to limit steam line flow during a steam line rupture. Over the extended life of the plant, it is essential to maintain the flow area of the flow restrictors used in the CLB to calculate the amount of steam released. The staff also believes that such components are susceptible to aging effects such as loss of material and cracking. Accordingly, the staff requests the applicant to provide the following information:

a) Are the SGs at FCS equipped with such components?

b) If so, include the components within the scope of license renewal and subject to an AMR, so that the intended function mentioned above can be maintained over the period of extended operation, or provide a justification for their exclusion.

2.3.1.3 <u>Reactor Vessel</u>

2.3.1.3-1 LRA Section 2.3.1.3 states that the vessel includes two leakage detection lines that are located between the vessel flange o-rings. The staff believes that the inner O-ring, the leakoff lines, and the outer O-ring all support the reactor vessel closure head flange pressure boundary (See letter dated October 27, 1999, from C. I. Grimes of NRC to D. J. Firth of B&WOG). Although in select cases the staff has accepted a site-specific technical justification, in general, the leakoff lines require an aging management review. It appears that the leakage detection lines at FCS have not been identified in the LRA (Table 2.3.1.3-1) as within scope, nor a plant-specific justification provided. Therefore, please provide a site-specific technical justification for FCS as to why aging management is not required, or perform an aging management review for these components.

2.3.2.1 <u>Safety Injection and Containment Spray</u>

2.3.2.1-1 LRA Section 2.3.2.1 states that the function of the containment spray (CS) system is to limit the containment structure pressure rise by providing a means for cooling the containment atmosphere after the occurrence of a LOCA. Pressure reduction is accomplished by spraying cool, borated water into the containment atmosphere. The CS System also reduces the leakage of airborne radioactivity by effectively removing radioactive particulates from the containment atmosphere. Removal of radioactive particulates is accomplished by spraying water into the containment atmosphere. The particulates become attached to the water droplets, which fall to the floor and are washed into the containment sump. During recirculation, the CS pumps discharge the borated water through two heat exchangers to a dual set of spray headers and spray nozzles in the containment. These spray headers are supported from the containment roof and are arranged to give essentially complete spray coverage of the containment horizontal cross sectional area. The staff believes that the above mentioned statements in the LRA justify the need to include the spray headers and spray nozzles within the scope of license renewal, and that an aging management review be submitted in order to preserve the spraying function from degradation due to cracking, corrosion, loss of material and/or blockage. However, it appears that the subject components and the intended functions were not identified in either LRA Table 2.3.2.1-1 or drawing E-23866-210-130 as being within scope and requiring aging management. Please include these components within scope and subject to an AMR or justify their exclusion.

2.3.3 Auxiliary Systems

2.3.3-1 In accordance with the LRA, the intake structure HVAC system is not within the scope of license renewal. If the intake structure HVAC system is required to ensure the functionality of the raw water pumps, then this HVAC system should be included within the scope of license renewal and the relevant components (including housings) should be subject to an AMR. On this basis, please confirm that the intake cooling water pumps do not require forced ventilation to perform their safety-related function, or include the intake structure HVAC system within the scope of license renewal in accordance with 10 CFR 54.4. In addition, if the system contains passive, long-lived components, please confirm that they are subject to an AMR in accordance with 10 CFR 54.21, or justify their exclusion.

2.3.3.1 Chemical and Volume Control System

2.3.3.1-1 On P&ID E-23866-210-121, Sheet 2, the de-borating filter is not included in the scope for pressure boundary function. The P&ID shows normally-open valves with no signal to close on either side of the de-borating filter. The staff believes that this portion of the system meets the 10 CFR 54.4(a) scoping criteria and should be included within scope. Further, the staff also believes that the filter housing is passive and long-lived and, thus, should be subject to an AMR. The applicant should include this component within the scope of license renewal and subject to an AMR, or justify its exclusion.

2.3.3.2 Spent Fuel Pool Cooling

2.3.3.2-1 USAR Section 9.6.2 states that the fuel transfer canal drain pumps are utilized to provide spent fuel pool make-up water from the safety injection and refueling water tank. Drawing 11405-M-11 for the safety injection system depicts a transition to the spent fuel pool cooling system at valve AC-307. However, drawing 11405-M-11 for the spent fuel pool cooling system does not depict a transition to the safety injection system at valve AC-307. Please clarify whether the embedded piping to the right of valve AC-307 on drawing 11405-M-11 is within the scope of license renewal and subject to an AMR.

2.3.3.2-2 License renewal boundary flags on drawing 11405-M-6, Sh. 2 for the spent fuel pool cooling system, depict a transition from the spent fuel pool cooling system to the liquid waste disposal system at valve WD-1161 and a transition from the spent fuel pool cooling system to the safety injection system at valve WD-843, while drawing 11405-M-6, Sh. 2, for the liquid waste and safety injection systems shows a direct interface between the safety injection and the liquid waste disposal systems at valve WD-843 with no indication of an interface with the spent fuel pool cooling system anywhere on the drawing. Although many drawings have multiple versions, each showing distinctly different information related to license renewal, the application fails to reference the associated drawings with uniquely identifiable drawing numbers. In order to determine whether the applicant has properly identified components within the scope of license renewal and subject to an AMR, the staff requests the following clarifications:

1. Does valve WD-843 serve as a boundary between the safety injection and LWD systems, as indicated in drawing 11405-M-6, sheet 2, for the LWD system, or does it serve as a boundary between the safety injection and spent fuel pool systems, as indicated in drawing 11405-M-6, Sheet 2, for the SFP system?;

2. Is the piping between valves WD-843 and WD-1161, including the SFP branch line from drawing 11405-M-11, within the scope of license renewal and subject to an AMR?; and

3. Is valve WD-1161 in the LWD system, or does it serve as a boundary between the SFP and LWD systems?

2.3.3.3 Emergency Diesel Generators (EDGs)

2.3.3.3-1 The components (expansion joints and mufflers) are identified in drawing E-4183, Rev.1, “Diesel Generator Intake Air & Exhaust Diagram,” as being within the scope of license renewal. However, these components are not contained in LRA Table 2.3.3.3-1, which lists components subject to an AMR. The staff believes that these components are passive and long-lived and, therefore, should be subject to an AMR. Please clarify whether these components are subject to an AMR, or justify their exclusion.

* Expansion joints (C-1, E~F-1, C-8, and E~F-8)
* Mufflers (C-4 and F-4)

2.3.3.3-2 The radiator exhaust ductwork is neither identified in drawing E-4183 as being within the scope of license renewal nor included in LRA Table 2.3.3.3-1, which lists components subject to an AMR. The staff believes that this component is long-lived with a passive function and, therefore, is subject to an AMR. Please clarify whether this component is subject to an AMR, or justify its exclusion.

* Radiator exhaust ductworks (E~C-1 and E~F-1)

2.3.3.4 Emergency Diesel Generator Lube Oil and Fuel Oil

2.3.3.4-1 Air box drain drums and camshaft counter weight housings are identified in drawing B120F03001, sheets 1 and 2, “Lube Oil System Schematic,” as being within the scope of license renewal. However, these components are not contained in LRA Table 2.3.3.4-1 which lists components subject to an AMR. The staff believes that these components are passive and long-lived and, therefore, are subject to an AMR. Please clarify whether these components are subject to an AMR, or justify their exclusion.

* Air box drain drums (sh.1 C-7~8, sh.2 C-7~8)
* Camshaft counter weight housings (sh.1 D-5~6, sh.2 D-5~6)

2.3.3.5 Auxiliary Boiler Fuel Oil and Fire Protection Fuel Oil

2.3.3.5-1 The system description for the auxiliary boiler fuel oil system in LRA Section 2.3.3.5, "Auxiliary Boiler and Fuel Oil and Fire Protection Fuel Oil," lists the component types that are subject to AMR and lists the intended function for the components. However, the LRA description does not provide sufficient information on the license renewal intended function of the system to determine, with reasonable assurance, that all the components required by 10 CFR 54.4 to be within the scope of license renewal and subject to an AMR have been correctly identified. Please provide more information concerning the intended function(s) of this system. This information should be sufficient to justify the license renewal boundaries depicted on the referenced drawings, and identify which specific components are within the scope of license renewal and subject to AMR.

2.3.3.5-2 LRA Table 2.3.3.5-1 states that hoses and hose couplings will be replaced based on performance or condition in accordance with the periodic surveillance and preventive maintenance program. In accordance with the guidance provided in Table 2.1-3 of the SRP-LR, hoses and hose couplings are consumable components and, as such, are typically replaced based on performance or condition monitoring that identifies whether these components are at the end of their qualified lives and may be excluded, on a plant-specific basis, from an AMR. The guidance further states that the applicant should identify the standards that are relied on for the replacement as part of the methodology description. The periodic surveillance and preventive maintenance program, as described in the LRA, does not provide such a methodology description. On this basis, the staff requests the applicant to identify the standards that are relied on for replacement.

2.3.3.6 Emergency Diesel Jacket Water

2.3.3.6-1 Instrument manifolds are identified in drawing B120F04002, sheets 1 and 2, "Jacket Water Schematic," as being within the scope of license renewal. However, these components are not contained in LRA Table 2.3.3.6-1, which lists components subject to an AMR. The staff believes that these components are passive and long-lived and, therefore, are subject to an AMR. Please clarify whether these components are subject to an AMR, or justify their exclusion.

2.3.3.7 Starting Air

2.3.3.7-1 LRA Table 2.3.3.7-1, which lists components subject to an AMR, include filters/strainers. However, these components are not shown in drawing B120F07001, sheets 1 and 2, "Starting Air System Schematic," as being within the scope of license renewal. The staff believes that these components meet the scoping criteria of 10 CFR 54.4(a)(1) and, therefore, should be within scope. Further, these components are passive and long-lived and, therefore, should be subject to an AMR. Please clarify whether these components are within the scope of license renewal and subject to an AMR, or justify their exclusion.

2.3.3.8 Instrument Air

2.3.3.8-1 LRA Section 2.3.2.2 states that containment isolation valves and associated piping in the compressed air system are subject to an AMR. LRA Section 2.3.3.8 states that the function of the compressed air system is to serve as the source of air for the instrument air system. Section 9.12 of the USAR describes the compressed air system to include air compressors, receivers, and air dryers. The staff believes these components, as well as valve bodies, piping, bolting, and valve operator bodies of the compressed air system, should be included within the scope of license renewal and should be subject to an AMR. The LRA description does not provide sufficient information on the license renewal intended function of the system to determine, with reasonable assurance, that all the components required by 10 CFR 54.4 to be within the scope of license renewal and subject to an AMR have been correctly identified. Please provide more information concerning the intended function(s) of this system. This information should be sufficient to justify the license renewal boundaries depicted on the referenced drawings, and identify which specific components are within the scope of license renewal and subject to an AMR.

2.3.3.8-2 The system description in LRA Section 2.3.3.8 lists the instrument air system component types that are subject to an AMR and lists the intended function of the components. However, the LRA description does not provide sufficient information on the license renewal intended function of the system to determine, with reasonable assurance, that all the components required by 10 CFR 54.4 to be within the scope of license renewal and subject to an AMR have been correctly identified. Please provide more information concerning the intended function(s) of this system. This information should be sufficient to justify the license renewal boundaries depicted on the referenced drawings, and identify which specific components are within the scope of license renewal and subject to an AMR.

2.3.3.9 Nitrogen Gas

2.3.3.9-1 The system description in LRA Section 2.3.3.9, describes the function of the NG system to be to charge the safety injection tanks and to provide nitrogen cover for various tanks. However, the referenced drawings show the license renewal boundaries only going from the tanks to the first isolation valve. Also, the LRA description does not provide sufficient information on the license renewal intended function of the system to determine, with reasonable assurance, that all the components required by 10 CFR 54.4 to be within the scope of license renewal and subject to an AMR have been correctly identified. Please provide more information concerning the intended function(s) of this system. This information should be sufficient to justify the license renewal boundaries depicted on the referenced drawings, and identify which specific components are within the scope of license renewal and subject to an AMR.

2.3.3.9-2 On Drawing 11405-M-42 Sheet 1, location C3, Valve NG-116 is highlighted as being within the scope of license renewal. The upstream and downstream side piping connected to NG-116 is not highlighted as being within the scope of license renewal. According to LRA Table 2.3.3.9-1, the intended function of the valve body component group is pressure boundary. The failure to include the connected piping within scope and subject to an AMR could defeat that function. Include the subject piping within the scope of license renewal and subject to an AMR or provide justification for not including the connected piping within the license renewal boundary.

2.3.3.10 Containment Heating, Ventilation, and Air Conditioning (HVAC)

2.3.3.10-1 The system description includes the nuclear detector well cooling as one of four sub-systems. This sub-system and its boundaries are not highlighted on P&ID 11405-M-1, sheet 1, Rev. 72 at locations A3 and A7 to indicate that it is within the scope of license renewal. Because of the way LRA Table 2.3.3.10-1 is presented, the staff is unable to determine if these SCs are included in the table. Therefore, the applicant should verify that the sub-system and SCs are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 54.21 or justify its exclusion.

2.3.3.10-2 LRA Table 2.3.3.10-1 lists “dampers” as a type of component subject to an AMR. Dampers are active components and, therefore, not subject to an AMR. However, per the staff’s draft position on housings (see letter from P.T. Kuo to Alan Nelson and David Lochbaum, “License Renewal Issue: Guidance on the Identification and Treatment of Housings for Active Components,” May 1, 2002), damper housings within the scope of license renewal are passive and long-lived, and, therefore, are subject to an AMR. Please clarify whether the dampers are subject to an AMR and provide the basis for their inclusion. Also, please clarify whether damper housings are subject to an AMR or justify their exclusion.

2.3.3.10-3 The description of sub-systems does not identify the air supply or return from the seismic skirt (Control Element Drive Motor) cooling. On the referenced drawing, 11405-M-1 sheet 1 Rev.75 at locations D4 and D6, the fans that provide flow for the seismic skirt are identified as within the scope of license renewal. The staff believes that the fan housings are passive and long-lived, and are not included in LRA Table 2.3.3.10-1. Therefore, the applicant should verify that the fan or blower housings are subject to an AMR and identify any other components associated with this function (i.e., duct from air supply plenum, return duct, damper VA-58) that are also subject to an AMR in accordance with 10 CFR 54.4 and 54.21 or justify their exclusion.

2.3.3.11 Auxiliary Building Heating, Ventilation, and Air Conditioning (HVAC)

2.3.3.11-1 LRA Section 2.3.3.11 references drawings to define the scope of license renewal. Drawing 11405-M-2 Sheet 2 Rev. 61 at location F3 indicates that the license renewal scope continues on Drawing 11405-M-1 sheet 2 , “169 Z” at location F3. Drawing 11405-M-1 sheet 2 Rev. 25, “171 Z” at location E1, which is the continuation of Drawing 11405-M-2 Sheet 2 Rev. 61 at location F3, is not highlighted and there is no indication of the LRA scope boundary. Clarify whether the SCs which are in the unhighlighted continuation portion of the auxiliary building HVAC system that extends to the ventilation discharge duct are within the scope of license renewal and subject to an AMR, or justify their exclusion.

In addition, LRA Table 2.3.3.11-1 “Auxiliary Building HVAC” includes dampers as a component type that is within the scope of license renewal. However, damper(s) housings are not included. The staff believes that damper housings are passive and long-lived components and should be included within the scope of license renewal. Please clarify whether the damper housings are within the scope of license renewal and subject to an AMR. If not, please justify the exclusion.

2.3.3.12 Control Room Heating, Ventilation, and Air Conditioning (HVAC) and Toxic Gas Monitoring

2.3.3.12-1 In order to comply with the requirements of General Design Criteria (GDC) 19, a control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including loss-of-coolant-accidents. Typically, a main control room envelope (MCRE) is established and maintained habitable, from which the main control room operators can take actions to operate the nuclear power unit safely.

a. In LRA Table 2.3.3.12-1, the list of component types subject to aging management review appears to be incomplete. Describe the areas that constitute the MCRE for FCS, and verify that all control room ventilation system components inside and/or outside the MCRE, which are relied on to perform safety-related intended functions, are identified as within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4 and 10 CFR 54.21, or justify their exclusion. These passive and long-lived components should include, but are not limited to, the housings of filtration unit components, including demisters, heaters, prefilters, high efficiency particulate air (HEPA) filters, and adsorbers, the housings of air handling units and fan coil units, housings of fire dampers and control dampers, housings of air intakes and louvers, and housings of exhaust fans, and all associated supply, return and exhaust ductwork.

b. The staff believes that sealant materials used to maintain positive pressure in the MCRE are passive and long-lived components and are, thus, subject to an AMR. Clarify whether sealant materials at FCS used to maintain the MCRE at positive pressure with respect to adjacent areas in order to prevent unfiltered inleakages into the MCRE are included within the scope of license renewal and subject to an AMR, and if so, provide the relevant information to complete LRA Table 2.3.3.12-1 of the

LRA. If the sealants are not considered subject to an AMR, provide justification for their exclusion.

2.3.3.13 Ventilating Air

2.3.3.13-1 For the ventilating air system, the LRA states that the passive equipment within the license renewal boundary is contained within the emergency diesel generator rooms. This equipment is included in Table 2.3.3.13-1. However, the housings for the exhaust fans are not included in the table. The staff believes these housings are passive and long-lived and should be within the scope of license renewal. Therefore, the applicant should include these SCs in LRA Table 2.3.3.13-1, in accordance with 10 CFR 54.4 and 54.21 or justify their exclusion.

2.3.3.14 Fire Protection

2.3.3.14-1 LRA Section 2.1.4.1, "Plant Systems" states on page 2-8 that, "The Non-CQE FP SSCs satisfying the regulation are identified in the Fire Hazards Analysis (FHA)." LRA Section 2.3.3.14, "Fire Protection" states that the plant is divided into unique plant areas as required by Appendix A to NRC Branch Technical Position APCSB 9.5-1 and Appendix R to 10 CFR Part 50. LRA Section 2.3.3.14 also states that more information on the FP system can be found in Section 9.11 of the USAR. The USAR states that the updated FHA documents the FP program comparison matrix to Appendix A to BTP 9.5-1 and Appendix R, Section III.G, III.J., and III.O requirements. It appears that the applicant has used the FHA as the primary scoping tool to identify FP SSCs (Non-CQE) required to satisfy 10 CFR 50.48.

a. Discuss how plant commitments contained in drawings, the USAR and other plant documentation which may also reflect the FCS fire protection current licensing basis, were reviewed to ensure that all FP SSC's relied upon for compliance to 10 CFR 50.48 were included within the scope of license renewal.

b. If the FHA is the primary scoping tool, describe how it is updated to reflect changes in, and commitments to, the approved FP program.

2.3.3.14-2 The staff identified from its review of the flow diagrams that the following components have been excluded from within the scope of license renewal. Please provide the basis for exclusion of the following components from within the scope of license renewal:

a. 11405-M-266, Sheet 1B - 12" Hose Valve Heads Twelve-inch hose valve heads are not highlighted as being within the license renewal boundary in this flow diagram and appears to be excluded from within the scope of license renewal. Provide the basis for exclusion since it appears that these valves provide a pressure boundary intended function, consistent with the rest of the fire protection system piping, which is identified as within the scope of license renewal. If the hose valve heads are brought into scope, provide the aging management information for the components.

b. 11405-M-266, Sheet 8 - Fire Hose Connections The piping leading to the fire hose connections are not highlighted as being within the license renewal boundary and appear to be excluded from within the scope of license renewal. Provide the basis for exclusion since it appears this piping provides a pressure boundary intended function for the FP water supply. If the hose connections are brought into scope, provide the aging management information for the components.

c. 11405-M-266, Sheet 8A - Piping Leading to Transformer Sprinklers The piping leading to the transformer sprinklers is excluded from the scope of license renewal, as shown in the flow diagram. The staff believes that the piping should be included within scope and subject to an AMR. The staff's basis is provided below.

Background information

Title 10 CFR 54.4(a)(3) requires structures, systems, and components (SSCs) to be included within the scope of license renewal if they are relied upon to comply with 10 CFR 50.48. Title 10 CFR 50.48 requires each nuclear power plant to have a fire protection program that satisfies Criterion 3 of Appendix A of 10 CFR Part 50 (GDC 3). The fire protection program commitments are documented in OPPD's fire protection license condition, which states that "Omaha Public Power District shall implement and maintain in effect all provisions of the *approved Fire Protection Program* as described in the Updated Safety Analysis Report for the facility and as approved in the SERs dated....." The documents described in the license condition show that FCS commits to meet 10 CFR 50.48 through commitments made to Appendix A to Branch Technical Position APCSB 9.5-1 and Appendix R to 10 CFR Part 50.

In an SER dated January 31, 1994, the staff approved FCS' implementation of changes to the Technical Specifications, in accordance with GL 86-10 and GL 88-12. In addition, this SER shows that FCS included a standard fire protection license condition (see GL 86-10) which described the references which contain their plant-specific approved fire protection program. The NRC-approved fire protection program[1] is also described in

[1]The NRC-approved FP program is defined in GL 88-12 as including the fire protection and post-fire safe shutdown systems necessary to satisfy NRC guidelines and requirements; administrative and technical controls; the fire brigade and fire protection related technical staff; and other related plant features which have been described by the licensee in the FSAR, fire hazards analysis, responses to staff requests for additional information, comparisons of plant

Generic Letter (GL) 86-10, "Implementation of Fire Protection Requirements" and GL 88-12, "Removal of Fire Protection Requirements From Technical Specifications."

As stated, the NRC-approved fire protection program for FCS is documented in the fire protection license condition, which refers to a number of SERs as well as the USAR. USAR Table 9.11-1, "Extinguishing System Major Component Data" states on page 8 that water spray systems are provided for the main, auxiliary, and house transformers. In addition, page 56 of the FCS fire hazards analysis (FHA) also states that water spray systems are provided for the transformers. Recall that LRA Section 2.1.4.1, "Plant Systems," states on page 2-8 that, "The Non-CQE FP SSCs satisfying the regulation are identified in the Fire Hazards Analysis (FHA) and that the USAR states that the updated FHA documents the FP program comparison matrix to Appendix A to BTP 9.5-1. Furthermore, page 209 of Appendix A to the FHA, which compares the fire protection program to the guidance in Appendix A to Branch Technical Position (BTP) 9.5-1, states that the main power transformers are protected by water spray systems. The FHA's comparison between the fire protection program and Appendix R, Section III.G, III.J, and III.O requirements also identifies this spray function.

GDC 3 requires SSCs that are important to safety be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. As defined in GL 84-01, "NRC Use of Terms, 'Important to Safety' and 'Safety-Related,'" SSCs important to safety encompass the broad scope of equipment covered by Appendix A to 10 CFR Part 50, and include more than just safe shutdown equipment and those narrowly identified as safety-related. Safety-related SSCs are defined in 10 CFR Part 50.49(b)(1). For example, in accordance with 10 CFR 50.48, some portions of suppression systems may be required in plant areas where a fire could result in the release of radioactive materials to the environment, even if no safety-related or safe shutdown equipment is located in that particular fire area. This equipment is considered "important to safety." In addition, equipment provided for the fire protection program to satisfy Appendix A to BTP 9.5-1 is also considered "important to safety." The NRC staff documented this position on page 2-46 of NUREG-1743 (the

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designs to applicable NRC fire protection guidelines and requirements, and descriptions of the methodology for assuring safe plant shutdown following a fire.

license renewal safety evaluation for Arkansas Nuclear One-Unit 1)[2].

It is the staff's view that, based on these references (the license condition, along with the system descriptions in the USAR and the FHA), the piping leading to the transformer sprinklers is required to ensure that the spray systems can provide water to the transformers, as described in the USAR and FHA. Thus, they are part of the applicant's fire protection license condition and, as such, are required to meet 10 CFR 50.48. Therefore, these components should be within the scope of license renewal and subject to an AMR. On this basis, the staff requests the applicant to identify where these components are identified in the LRA as being within the scope of license renewal and subject to an AMR, or provide a technical justification for their exclusion. If the subject piping is brought into scope, provide the aging management information for the component.

d. 11405-M-266, Sheet 11 & Sheet 12 - Retard Chambers

The piping leading up to, and including, the retard chambers, are excluded from the scope of license renewal. It is the staff's understanding that the retard chamber is a metal container that fills with water when there is a surge in water pressure. It absorbs the pressure increase, thereby allowing the alarm pressure switch to operate only in an actual alarm condition. The drip cup at the bottom of the chambers allows the water surge to drain out. The staff's technical concern is that retard chambers require maintenance to make sure the drip valve stays clean and does not get clogged from corrosion and rust, which could lead to false alarms.

NUREG-1800, "Standard Review Plan for Review of License Renewal Applications For Nuclear Power Plants," includes water-based fire protection components within the scope of license renewal and subject to an AMR. Sprinkler system alarm components, such as retard chambers, orifice plates, and associated piping are typically within the scope of license renewal and require an AMR. These passive, long-lived components provide a pressure boundary function during system activation and are made of carbon-steel which is subject to a loss of material as a result of corrosion.

[2]Excerpt from NUREG-1743: "The exclusion of any FP SSC on the basis that its intended function is not required for the protection of safe-shutdown equipment is not acceptable to the staff, in itself. Compliance with 10 CFR 50.48 requires a FP program that goes beyond safe shutdown, and includes such requirements as a means to limit fire damage to SSCs that are important to safety...."

The wet pipe suppression system identified on these drawings is needed for protection of the radiation process buildings. On page 258 of the FCS FHA (EA-FC-97-001, Rev. 3), the licensee documents how it meets the intent of Appendix A to BTP 9.5-1. Specifically, Section F.14, “Radwaste Building” states that FCS meets the intent of Appendix A to BTP 9.5-1 by installing automatic sprinklers in the Linder Holdup Room of the radwaste processing building, due to the extra fire loading associated with high integrity containers (HICs). Because this spray function is documented in the FHA, the associated fire protection SSCs which support this water suppression system are required for compliance with 10 CFR 50.48 (for the same reasons discussed above regarding the transformer sprinkler piping) and, as such, are required by 10 CFR 54.4(a)(3) to be included within the scope of license renewal. Exclusion of these portions of the suppression systems, on the basis that no safety-related or safe shutdown equipment is contained in the radiation process building, is not acceptable on the basis that the scope of 10 CFR 50.48 provides for the protection of all SSCs important to safety, as discussed above for the transformer sprinkler piping.

On the basis of the above discussion, the staff requests the applicant to identify where these components are identified in the LRA as being within the scope of license renewal and subject to an AMR, or provide a technical justification for their exclusion. If the retard chambers are brought into scope, provide the aging management information for the components.

e. <u>11405-M-259, Sheet 1 - Fire Protection Jockey Pump</u>

(See the background information regarding 10 CFR 50.48, the FCS license condition, the NRC-approved fire protection program, and GDC 3 for RAI 2.3.3.14-2.c above)

The piping leading up to, and including, the jockey pump, is excluded from the scope of license renewal. The fire protection license condition states that “Omaha Public Power District shall implement and maintain in effect all provisions of the approved Fire Protection Program as described in the Updated Safety Analysis Report for the facility and as approved in the SERs dated.....” Appendix A to Branch Technical Position, Section E.2.(c), states that “Details of the fire pump installation should as a minimum conform to NFPA 20, ‘Standard for the Installation of Centrifugal Fire Pumps.’” NFPA-20 states that a fire pump shall not be used as a pressure maintenance pump. USAR Section 9.11, page 5, states that the pressurization of supply piping is provided by means of a jockey pump. USAR Table 9.11-1, “Extinguishing System Major Component Data” identifies the jockey pump. In addition, Page 233 of the FHA, “Appendix A to BTP 9.5-1 Comparison,” states that NFPA-20 was used as a guideline in the fire pump installation. Because this pressurization function is documented in the USAR, the associated fire protection SSCs are required for compliance with 10 CFR 50.48 (for the same reasons discussed above regarding the transformer sprinkler piping) and, as such, are required by 10 CFR 54.4(a)(3) to be included within the scope of license renewal.

It is the staff's view that, based on the references (the license condition and the branch technical position, NFPA-20, the USAR, and the FHA), the jockey pump casing should be within the scope of license renewal and subject to an AMR. On this basis, the staff requests the applicant to identify where the jockey pump is identified in the LRA as being within the scope of license renewal and subject to an AMR, or provide a technical justification for its exclusion. If the jockey pump is brought into scope, provide the aging management information for the component.

2.3.3.14-3 The staff identified from its comparison of USAR Section 9.11, "Fire Protection System" to LRA Table 2.3.3.14-1, that the following components are not identified as fire protection components with intended functions required for compliance to 10 CFR 50.48. Provide the basis for exclusion of the following components from within the scope of license renewal:

a. Fire Hydrants In accordance with the USAR Section 9.11, Page 6, it states that "fire hydrants are located approximately 50 feet from the structure and are placed approximately every 300 feet along the fire ring main around the plant buildings." It is the staff's view that, based on the references (the license condition and the USAR), the hydrants should be within the scope of license renewal and subject to an AMR. Verify that the hydrants identified in USAR Table 9.11-4, "Fire Hose Locations" have been included in scope and are subject to an AMR. Provide justification for the exclusion of any fire hydrants required for compliance to 10 CFR 50.48. If the fire hydrants are brought into scope, provide the aging management information for the components.

b. CO_2 system (Also see the background information regarding 10 CFR 50.48, the FCS license condition, the NRC-approved fire protection program, and GDC 3 for RAI 2.3.3.14-2.c above.)

The Turbine Generator Exciter is protected by a total flooding CO_2 system, utilizing high pressure CO_2 storage tanks as a supply source, as stated in USAR Section 9.11, page 14. The applicant has not identified the CO_2 system, including storage tanks and associated piping, as being included in the scope of license renewal and subject to an AMR, even though it appears to be credited in the documentation listed in the fire protection license condition.

In addition, Page 240 of Appendix A to the FHA states that a carbon dioxide system is installed in the generator exciter housing and that NFPA 12, "Standard on Carbon Dioxide Extinguishing Systems," was used as a guideline in the installation. It is the staff's view, based on the references (the license condition and the USAR), that the CO_2 system should be within the scope of license renewal and subject to an AMR.

Identify where the carbon dioxide system is identified in the LRA as being within the scope of license renewal and subject to an AMR, or provide a technical justification for its exclusion. If the system is brought into scope, provide the aging management information for the system components.

2.3.3.14-4 LRA Table 2.3.3.14-1 states that hoses are not subject to an AMR because they are replaced based on condition in accordance with applicable NFPA standards and plant procedures for fire protection equipment. In accordance with the guidance provided in Table 2.1-3 of the SRP-LR, hoses are consumable components and, as such, are typically replaced based on performance or condition monitoring that identifies whether these components are at the end of their qualified lives, and may be excluded, on a plant-specific basis, from an AMR. The guidance further states that the applicant should identify the standards that are relied on for the replacement as part of the methodology description. The LRA does not provide a methodology description or a standard for replacement. On this basis, the staff requests the applicant to provide a methodology description and identify the NFPA standards and plant implementing procedures that are relied on for replacement.

2.3.3.15 Raw Water

2.3.3.15-1 Drawing 11405-M-100 depicts several license renewal boundary flags at locations E-8, D-8, and D-7, that are at design class boundaries not associated with an isolation valve. Please justify the location of these boundaries with regard to protection of essential systems from internal flooding, or relocate the license renewal boundary to an appropriately located isolation valve.

2.3.3.15-2 USAR Section 9.8.2 states that four raw water pumps are installed in the intake structure to provide screened river water to the component cooling heat exchangers. The intake structure screens perform an apparent intended function of preventing debris from reaching the pumps that could block flow to, or otherwise cause the failure of, the safety-related raw water system. However, LRA Table 2.3.3.15-1 does not identify the intake structure screens as components subject to an aging management review. Please clarify whether the intake structure screens are subject to an AMR, or justify their exclusion.

2.3.3.16 Component Cooling

2.3.3.16-1 Drawing 11405-M-12, Sh. 1, for the component cooling water system depicts the sample chiller and the associated component cooling water supply and return piping at drawing location B-6 as outside the scope of license renewal. However, drawing 11405-M-12, Sh. 1, for the primary plant sampling system depicts the sample chiller as within scope and notes a transition to the component cooling water system for the associated supply and return piping. It is unclear to the staff whether these components are within the scope of license renewal and subject to an AMR, the basis for their inclusion or exclusion, and to what system(s) these components belong (for the purposes of license renewal). Please clarify whether the sample chiller and the associated component cooling water supply and return piping are within the scope of license renewal and subject to an AMR, the basis for inclusion within scope and subject to an AMR, and for what system(s) these components are within scope and subject to an AMR, or justify their exclusion.

2.3.3.16-2 Drawing 11405-M-119, for the component cooling water system depicts the control element assembly seal coolers as within license renewal scope as part of the reactor vessel internals, and the associated component cooling water supply and return piping as within scope for the component cooling water system. However, LRA Table 2.3.1.1-1, which lists components comprising the reactor vessel internals, does not include the control element assembly seal coolers nor their intended function of maintaining the component cooling water system pressure boundary. Also, LRA Section 2.3.1.1, does not reference drawing 11405-M-119. Please clarify whether the control element assembly seal coolers are included within the scope of license renewal and subject to an AMR or justify their exclusion. In addition, please provide drawings and other design information for the control element assembly seal area that provides sufficient detail to identify other potential intended functions of the seal cooler, such as reactor coolant system pressure boundary and heat transfer (i.e., the seal must be cooled to maintain reactor coolant system pressure boundary integrity)."

2.3.3.16-3 Drawing 11405-M-40, Sh. 1, for the component cooling water system depicts the containment air cooling coils as within the scope of the containment heating, ventilation, and air conditioning system. However, drawing 11405-M-1, Sh. 1, which is referenced by the LRA for the containment heating, ventilation, and air conditioning system, does not clearly depict the containment air cooling unit interface with the component cooling water system such that the components subject to aging management review can be identified. As discussed in the staff's letter to the Nuclear Energy Institute and the Union of Concerned Scientists, "License Renewal Issue: Guidance on the Identification and Treatment of Housings for active Components," May 1, 2002, housings of active components, including heating and cooling coils, may perform a critical pressure retention and/or structural integrity function which, should that function not be maintained, could prevent the associated active component from performing its function. The staff believes that the containment air cooling coils provide such an intended function and are passive and long-lived. Therefore, the staff concludes that these components should be subject to an AMR. Please clarify whether the containment air cooling coils are subject to an AMR, or justify their exclusion.

2.3.3.16-4 Drawing 11405-M-10, Sh. 2, for the component cooling water system depicts the nitrogen pressurization line to the component cooling water surge tank as within the scope of the component cooling water system. However, drawing 11405-M-42, Sh. 1, which is referenced by the LRA for the nitrogen gas system, depicts the interfacing line within the scope of the nitrogen gas system rather than the component cooling water system. Please resolve the discrepancy between these drawings.

2.3.3.16-5 Drawing E-23866-210-120, Sh. 1A, for the chemical and volume control system identifies the letdown heat exchanger as within scope. However, drawing 11405-M-10, Sh. 3, for the component cooling water system fails to depict a transition to the chemical and volume control system at the letdown heat exchanger. In addition, drawing E-23866-210-120, Sh. 1A for the chemical and volume control system and drawing E-23866-210-120, Sh. 1A for the reactor coolant system are distinct license renewal drawings, but the LRA uses the identical reference number. Please clarify the noted discrepancies and clarify whether the component cooling water supply and return piping for the letdown heat exchanger is within the scope of license renewal and subject to an AMR.

2.3.3.16-6 Drawing 11405-M-10, Sh. 3, for the component cooling water system depicts a transition to the gaseous waste disposal system at the gas compressor seal water heat exchangers. However, drawing 11405-M-98, Sh. 1, for the gaseous waste disposal system fails to depict a transition to the component cooling water system at the gas compressor seal water heat exchangers. Please resolve these discrepancies and clarify whether the subject components (gas compressor seal water heat exchangers and associated component cooling water interfaces) are within the scope of license renewal and subject to an AMR.

Drawing 11405-M-10, Sh. 3, for the component cooling water system depicts a transition to the gaseous waste disposal system at the gas compressor seal water heat exchangers. However, drawing 11405-M-98, Sh. 1, for the gaseous waste disposal system fails to depict a transition to the component cooling water system at the gas compressor seal water heat exchangers. Please resolve the discrepancies between drawings.

2.3.3.16-7 Drawing 11405-M-10, Sh. 3, for the component cooling water system depicts relief valves for shutdown cooling heat exchangers AC-4A and AC-4B and the spent fuel pool heat exchanger (valves AC-1026, AC-1027, and AC-1059, respectively) as gagged. However, neither the valves' inlet piping nor the valve bodies are indicated as being within the scope of license renewal and subject to aging management review by red overprinting or an appropriate note. In addition, the gagging devices, which also perform an apparent pressure boundary intended function, are not listed in LRA Table 2.3.3.16-1 as being subject to aging management review. Please clarify whether the inlet piping, bodies, and gagging devices associated with the above-referenced valves are within the scope of license renewal and subject to an AMR, or justify their exclusion.

2.3.3.19 <u>Primary Sampling</u>

2.3.3.19-1 Drawing 11406-M-12, Sheet 1 shows sample heat exchangers SL-3, SL-8A, S-8B, and sample cooler SL-51 as being within the scope of license renewal for the primary sampling system. The intended functions of these components are heat transfer and pressure boundary. In all four cases, the primary sampling system inlet and outlet piping is not within the scope of license renewal. The failure of this piping could compromise the pressure boundary function of the heat exchangers and sample chiller. Provide justification for not including the inlet and outlet piping within the scope of license renewal.

2.3.3.20 Radiation Monitoring-Mechanical

2.3.3.20-1 Drawing 11405-M-1, Sheet 2 is the only drawing listed as showing the license renewal boundaries for this system. The drawing appears to show only three equipment cabinets as being within the scope of license renewal. LRA Table 2.3.3.20-1 lists five component types subject to aging management review. Clarify where the components within the scope of license renewal for the Radiation Monitoring-Mechanical system are shown and/or listed. Provide an inclusive drawing or drawings showing the Radiation Monitoring-Mechanical system license renewal boundaries. This information is necessary in order for the staff to have reasonable assurance that all the SSCs have been correctly identified as being within scope and subject to an AMR in accordance with 10 CFR Part 54.

2.3.4 Steam and Power Conversion Systems

2.3.4-1 The steam generator blowdown system is identified in LRA Section 3.4 as being included in the steam and power conversion systems group. The steam generator blowdown system is not part of the steam and power conversion systems listed in LRA Section 2.3.4. Additionally, LRA Table 2.2-1, "Plant Level Scoping Results," lists the steam generator feedwater blowdown system as being within the scope of license renewal. Given these discrepancies, in order for the staff to understand whether the steam generator feedwater blowdown system is within scope and subject to an AMR, please identify where in the application the steam generator feedwater blowdown system is addressed.

2.3.4.1 Feedwater

2.3.4.1-1 There are numerous pressure and level transmitters highlighted on drawing 11405-M-253, Sheet 1. What is the intended function of the pressure and level transmitters? From the drawing, it appears the instrument housings form part of a pressure boundary with their associated piping. Therefore, the instrument housings should be listed in LRA Table 2.3.4.1-1 as being subject to an AMR in accordance with 10 CFR 54.21. Justify not making the instrument housings subject to an AMR.

2.3.4.3 Main Steam and Turbine Steam Extraction

2.3.4.3-1 According to Drawing 11405-M-252, Sheet 1, the turbine drive for the steam-driven auxiliary feedwater (AFW) pump is within the scope of license renewal for the main steam system. Turbine casings are passive and long-lived and, therefore, should be subject to an AMR. However, the AFW turbine casing is not listed on LRA Table 2.3.4.3-1 as being subject to an AMR. Clarify whether the turbine casing is subject to an AMR, or justify its exclusion.

2.3.4.3-2 On Drawing 11405-M-252, Sheet 1, there are steam traps within the scope of license renewal for the main steam system. Steam traps are passive and long-lived and, therefore, should be subject to an AMR. Steam traps are not listed in LRA Table 2.3.4.3-1 as being subject to an AMR. Justify not including the steam traps in LRA Table 2.3.4.3-1."

2.3.4.3-3 LRA Table 2.3.4.3-1 lists strainers and filters as component types subject to an aging management review. The staff is unable to locate any strainers or filters within the scope of license renewal on Drawing 11405-M-252, Sheet 1. Clarify whether there are any filters or strainers within the scope of license renewal for the main steam system.

2.4.1 Containment

2.4.1-1 LRA Section 2.4.1 states that the tendon anchors are accessible for inspection, testing, and re-tensioning via the tendon access gallery located beneath the containment cylindrical wall and at the dome roof. LRA Table 2.4.1-1 lists all the components for the containment that are subject to an AMR. However, the tendon access gallery is not listed in the table. The staff believes that these components are long-lived components with a passive function and, therefore, are subject to an AMR in accordance with 10 CFR 54.21. Explain whether the concrete structure of the tendon access gallery is in scope and subject to an AMR for license renewal or provide justification for its exclusion.

2.4.1-2 LRA Table 2.4.1-1 lists containment equipment access hatch and personnel air lock as the components of the containment within the scope of license renewal. However, the applicant did not identify certain operable parts of the air lock if they require an AMR. The staff believes that many such components are long-lived with a passive function and, therefore, are subject to an AMR in accordance with 10 CFR 54.21. Explain whether the air lock door interlock system, equalizing valves, door seals, and operation mechanism (such as gears, latches, hinges, etc.) are in scope and subject to an AMR for license renewal.

2.4.1-3 LRA Table 2.4.1-1 uses containment concrete above grade, containment concrete below grade, and containment concrete in ambient air component types to represent all the reinforced concrete structures in the containment. It is not clear from the information provided which structures are included in these component groups. Please (1) identify which reinforced concrete structures are included within each component group and (2) explain whether the refueling cavity walls, containment sumps, and missile shields (passive, long-lived components) are included in any of these component groups.

2.4.1-4 LRA Table 2.4.1-1 uses the containment structural steel in ambient air to cover all steel structures in the containment. It is not clear from the information provided which structures are included in these component groups. Please identify steel structures and components in the containment that are subject to an AMR.

2.4.1-5 LRA Table 2.4.1-1 lists fuel transfer penetration as a containment component subject to an AMR. The staff believes that the fuel transfer tubes, expansion bellows, and flange supports are also passive long-lived components and, therefore, are also subject to an AMR. Please clarify whether these components are subject to an AMR, or justify their exclusion.

2.4.1-6 LRA Section 2.4.1 does not address the polar cranes, jib cranes and their supports. LRA Table 2.4.1-1 does not list any of their components. Are the main girders, runway rails, runway rail brackets, rail anchorages and embedment that support the polar cranes within scope of license renewal? If so, where in the LRA are they discussed? If not, justify not including them within the scope of license renewal. The staff believes that these components are long-lived components with a passive function and, therefore, are subject to an AMR in accordance with 10 CFR 54.21.

2.4.1-7 USAR Section 5.11 states that special steel structures were used around the steam generators for the purpose of limiting the motion of the steam generator in case a rupture occurs in the reactor coolant piping, the main steam piping, or the feedwater pipe. These special steel structures are not addressed in LRA Section 2.4.1. The staff believes that these passive long-lived structures are needed to ensure the functionality of the steam generators and are, therefore, within the scope of license renewal and subject to an AMR. Clarify whether these components are within scope and subject to an AMR, or justify their exclusion.

2.4.2-1 Please provide general plan drawings for the containment, auxiliary building, turbine building, and service building that show the structural arrangement and internals, and highlight the boundaries that are within the scope of license renewal. This information is necessary in order for the staff to have reasonable assurance that all the SSCs have been correctly identified as being within scope and subject to an AMR in accordance with 10 CFR Part 54.

2.4.2.1-1 LRA Section 2.4.2.1 states that the spent fuel pool, which consists of a stainless steel lined concrete structure, is contained within the auxiliary building. However, LRA Table 2.4.2.1-1 only lists the spent fuel pool liner as the component subject to an AMR. The staff believes that other components of the spent fuel pool structure meet the criteria in 10 CFR Part 54 and should be included within the scope of license renewal and be subject to an AMR. Please clarify what other component types listed in LRA Table 2.4.2.1-1 (or in another table) are applicable to the spent fuel pool structure.

2.4.2.2-1 LRA Section 2.4.2.2 describes the turbine building and service building. LRA Table 2.4.2.2-1 lists the component groups that have the intended functions to act as structural support to non-CQE, pipe restraints, and high-energy-line-break shielding. It is not clear from the information provided which portions of these buildings are in scope and what are the components that perform these intended functions. Specify the structural components of the turbine building and service building that are in scope for license renewal and subject to an AMR.

2.4.2.3-1 LRA Section 2.4.2.3 states that the intake structure is a multi-floored Class 1 structure that houses both CQE and non-CQE systems and components and the fuel tank of the diesel-driven fire pumps. However, most of the component groups listed in LRA Table 2.4.2.3-1 are not addressed in LRA Section 2.4.2.3. There are no structural drawings in the LRA that can be used to check if anything is missing. Provide information on the components and equipment supports for the intake structure that are subject to an AMR. Furthermore, are there any bridge crane, cable trenches, conduits, hatches, and missile barriers within the boundary of the intake structure that are within scope and subject to an AMR for license renewal? This information is necessary in order for the staff to have reasonable assurance that all the SSCs have been correctly identified as being within scope and subject to an AMR in accordance with 10 CFR Part 54.

2.4.2.4-1 LRA Section 2.4.2.4 states that the commodity boundary includes all deep foundation piles within the scope of license renewal, consisting of Class A, Class B, concrete caisson, and H-pile designs. These building piles provide structural support for the auxiliary building, containment, intake structure, and the turbine building. The deep foundation piles have the intended function to transfer the heavy foundation loads to the bedrock. However, these piles are deeply penetrated into soil under the thick foundations. As a result, inspection of these deep foundation piles is questionable. The staff believes that these components are long-lived components with a passive function and, therefore, are subject to an AMR in accordance with 10 CFR 54.21. Explain what program manages the scoping inspection for the building piles and how the location of individual piles can be verified.

2.4.2.5 <u>Fuel Handling Equipment and Heavy Load Cranes</u>

2.4.2.5-1 Section 2.4.3.2 , “Structural Components Subject to an Aging Management Review,” of NUREG-1800 states that, in general, structural components are “passive” and “long-lived.” Thus, they are subject to an AMR if they are within the scope of license renewal. For each of the plant-level structures within the scope of license renewal, an applicant should identify those structural components that have intended functions. LRA Table 2.4.2.5-1 lists the following structures:

concrete slab removal cranes	containment crane
containment equipment hatch crane and jib	deborating demineralizing area crane
fuel transfer conveyor	fuel transfer carrier box
fuel transfer tube	new and spent fuel handling tools
refueling area crane	refueling machine
tilting machine	upper guide lift rig
waste evaporator equipment handling crane	reactor vessel closure head lift rig

For these SSCs the applicant should have identified structural components of beams, supporting columns, base plates, rails, rail clips, crane girders, crane bridge, structural members, monorail flanges, monorail, rail bolts, anchorages, trolley rails, trolley, baseplates and anchors for attachment to structures, and retaining clips. LRA Table 2.4.2.5-1 does not include the above structural components which should be included within the scope of license renewal and subject to AMR. If these structural components are not subject to AMR the applicant should provide a justification for their exclusion from LRA Table 2.4.2.5-1.

2.4.2.5-2 LRA Table 2.4.2.5-1 identifies the spent fuel storage racks as having an intended function of providing structural support to CQE reactivity control. However, the staff, after review of USAR Section 9.5.1.2, "Prevention of Criticality During Transfer and Storage," found that boral panels protected with stainless steel were attached to the racks to support the prevention of criticality in the spent fuel pool. The staff finds that the passive, long-lived boral panels and their stainless steel covering should be included within the scope of license renewal and subject to AMR, or the applicant should provide a justification for their exclusion. Additionally, the staff finds that the boral panels and the spent fuel storage rack arrangement support the prevention of criticality within the spent fuel pool. As a result, they perform an intended function of preventing criticality. The intended function of preventing criticality is not included within LRA Table 2.4.2.5-1. If it should not be included, the applicant should provide its justification for excluding the intended function of preventing criticality from LRA Table 2.4.2.5-1.

2.4.2.5-3 USAR Section 14.24, "Heavy Load Incident," identifies heavy load cranes that were evaluated following the guidelines of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." The evaluations were performed to determine compliance with the following criteria of NUREG-0612, Section 5.1:

1. Any release of radioactive material that may result from damage to spent fuel based on calculations involving accidental dropping of postulated heavy load will produce doses that are well within 10 CFR Part 100 limits of 300 rem thyroid, 25 rem whole body (analyses show that doses are equal to or less than one-fourth of Part 100 limits);

2. Damage to fuel and fuel storage racks based on calculations involving accidental dropping of a postulated heavy load does not result in a configuration of fuel such that k_{eff} is larger than 0.95;

3. Damage to the reactor vessel or the spent fuel pool based on calculations of damage following accidental dropping of a postulated load is limited so as not to result in water leakage that could uncover the fuel, (makeup water provided to overcome leakage should be from a borated water source of adequate concentration if the water being lost is borated); and

4. Damage to equipment in redundant or dual safe shutdown paths, based on calculations assuming the accidental dropping of a postulated heavy load,

will be limited so as not to result in a loss of required safe shutdown functions.

The staff found that the containment polar crane, auxiliary building crane, and intake structure overhead crane met one or more of the above criteria and as such should be included within the scope of license renewal, and its passive long-lived structural components should be subject to an AMR. Otherwise, the applicant should provide a justification for excluding the above cranes and their passive long-lived structural components from the scope of license renewal.

2.4.2.6 Component Supports

2.4.2.6-1 Title 10 CFR 54.21(a)(1) requires the applicant to identify and list structures and components subject to an AMR. The staff found that the applicant, in LRA Table 2.4.2.6-1, had not uniquely identified and listed component supports. Instead, LRA Table 2.4.2.6-1 generically refers to component support and provides the material and environment in the first column of the table. The staff believes that components such as battery racks, cable tray and conduit, cable tray and conduit supports, Class 1 (NSSS) supports, control boards, control room ceiling, HVAC duct supports, instrument racks and frames, instrument line supports, lead shielding supports, pipe supports, electrical and instrument panels and enclosures, equipment component supports, wireway gutters, and stair, platform and grating supports should be included within the scope of license renewal and subject to an AMR. Otherwise, the applicant should provide a justification for their exclusion from LRA Table 2.4.2.6-1.

2.4.2.7 Duct Banks

2.4.2.7-1 LRA Section 2.4.2.7 states that the elastomer joint and frame, manhole cover and flange, and foam blocks of manhole MH31 are within the structure boundary. The LRA also states that exposed conduit, conduit fittings, and seismic supports of manhole MH31 are evaluated in component supports (LRA Section 2.4.2.6). All other portions of manhole MH31 are evaluated as part of the intake structure (LRA Section 2.4.2.3). It is not clear from the information provided what portions on MH31 are evaluated in LRA Section 2.4.2.3. Identify what portions of manhole MH31 are evaluated in LRA Section 2.4.2.3 and what associated component types are listed in LRA Table 2.4.2.3-1.

2.4.2.7-2 USAR Section 8.5.1.(f) states that there are two pull boxes along the outside of the south wall of the auxiliary building and one manhole between the pull boxes and screen house. The staff believes that the manhole and pull boxes are passive and long-lived and, therefore, subject to an AMR. However, these components are not identified in LRA Table 2.4.2.7-1. Explain whether the manhole and pull boxes are evaluated as part of the duct banks that are within the scope of license renewal.

2.4.2.7-3 LRA Section 2.4.2.7 states that exposed conduit, conduit fittings, and seismic supports of manhole MH31 are evaluated in component supports (LRA Section 2.4.2.6). The staff could not identify where in LRA Section 2.4.2.6 the exposed conduit and conduit fittings are discussed. Clarify where in the LRA the exposed conduit and conduit supports associated with manhole MH31 are discussed.

2.5 Electrical

2.5-1 The screening results in LRA Section 2.5 do not include any offsite power system structures or components. Title 10 CFR 54.4(a)(3), requires that, "all systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for.....station blackout (10 CFR 50.63)" be included within the scope of license renewal. Title 10 CFR 50.63(a)(1), requires that each light-water-cooled power plant licensed to operate be able to withstand and recover from a station blackout of a specified duration (the coping duration) that is based upon factors that include "(i) The redundancy of the onsite emergency power sources; (ii) The reliability of the onsite emergency power sources; (iii) The expected frequency of loss of offsite power; and (iv) The probable time needed to restore offsite power." Licensees' plant evaluations followed the guidance specified in NRC Regulatory Guide (RG) 1.155, "Station Blackout," and NUMARC 87-00, " "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors" (1991), to determine their required plant specific coping duration. The criteria specified in RG 1.155 to calculate a plant specific coping duration were based upon the expected frequency of loss of offsite power and the probable time needed to restore offsite power, as well as the other two factors (onsite emergency ac power source redundancy and reliability) specified in 10 CFR 50.63(a)(1). In requiring that a plant's coping duration be based on the probable time needed to restore offsite power, 10 CFR 50.63(a)(1) is specifying that the offsite power system be an assumed method of recovering from an SBO. Disregarding the offsite power system as a means of recovering from an SBO would not meet the requirements of the rule and would result in a longer required coping duration. The function of the offsite power system within the SBO rule is, therefore, to provide a means of recovering from the SBO. This meets the criteria within license renewal 10 CFR 54.4(a)(3) as a system that performs a function that demonstrates compliance with the Commission's regulations on SBO. Based on this information, the staff requires that applicable offsite power system structures and components be included within the scope of license renewal and subject to an aging management review, or additional justification for their exclusion be provided.

The staff guidance on the scoping of equipment relied on to meet the requirements of the SBO rule are documented in the staff letter from NRC (Matthews) to NEI (Nelson) and UCS (Lochbaum) dated April 1, 2002 (ML020920464).

3.1 Reactor Coolant Systems

3.1-1 The staff's expectation is that every component that is identified as requiring an AMR in LRA Tables 2.3.1.1-1, 2.3.1.2-1, and 2.3.1.3-1, would have a link to AMR Table 3.1-1, 3.1-2, or 3.1-3 in the LRA. However, during its review, the staff found links to other system groups. Each link to a non-reactor system group is identified below. For each item, please provide a justification for the link, or provide the correct link to LRA Table 3.1-1, 3.1-2, or 3.1-3:

Component	Table	Link
RCP Pump Cover (Thermal Barrier)	2.3.1.2-1	3.2.1.09 (ESF system link) 3.3.2.74 (Auxiliary system link)
RCP Seal Water Cooler Tubes	2.3.1.2-1	3.2.1.09 (ESF system link) 3.3.2.74 (Auxiliary system link)
Steam Generator Blowdown Nozzles	2.3.1.2-1	3.4.1.02 (Steam and power generation system (SPCS) link) 3.4.1.05 (SPCS link) 3.4.1.06 (SPCS link) 3.4.1.13 (SPCS link)

3.1-2 Table 3.1-1 in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" summarizes the aging effects and aging management programs for reactor vessel, internals, and reactor coolant system components evaluated in Volume 2 of the GALL report, NUREG-1801. Table 1 in Volume 1 of NUREG-1801 identifies the item numbers in GALL that the group represents. The GALL item number identifies the component, its material, environment, aging effects/mechanisms and aging management program to manage the aging effect. Therefore, when an applicant indicates that the aging management review results are consistent with those reviewed and approved in NUREG-1801, they are inferring that all the components associated with the component group were evaluated by the applicant and contain materials, operate in an environment, are susceptible to aging effects/mechanisms, and have aging management programs that are consistent with those reviewed and approved in NUREG-1801. The staff is concerned that this conclusion does not apply to all GALL items that are listed in Table 1 in Volume 1 of NUREG-1801.

Table 3.1-1 of your application indicates that the Bolting Program is the aging management program for components identified as Items 3.1.1.19, 3.1.1.23, and 3.1.1.36. The bolting integrity program (LRA Section B.1.1) indicates, "The scope of the FCS Bolting Integrity Program includes those plant-specific components identified in LRA Tables 3.1.2 and 3.5.2 of this application for which the Bolting Integrity Program is identified as an aging management program." However, the LRA does not state that the scope of the program includes plant-specific components identified in LRA Table 3.1-1.

The applicant is requested to clarify this apparent discrepancy. In addition, the applicant is requested to confirm that when the application indicates a Row Number item identified in LRA Table 3.1-1 is consistent with NUREG-1801, all the GALL item numbers in Table 1 of Volume 1 of NUREG-1801 were evaluated by the applicant and they contain materials, operate in an environment, are susceptible to aging effects/mechanisms, and have aging management programs that are consistent with those reviewed and approved for the GALL item numbers in Table 1 of Volume 1 of NUREG-1801. If this is not true, identify all reactor vessel, internals, and reactor coolant system components that you indicate are consistent with NUREG-1801, but do not contain materials, operate in an environment, are susceptible to aging effects/mechanisms, or have aging management programs that are consistent with those reviewed and approved for GALL item numbers in Table 1 of Volume 1 of NUREG-1801.

3.1.1-1 Several line items in LRA Tables 3.1-1 (3.1.1.02, .3.1.1.16, and 3.1.1.17), and 3.1-2 (3.1.2.06 and 3.1.2.14) indicate that the steam generator program includes methods to detect general, crevice and pitting corrosion of the steam generator shell assembly and loss of section thickness due to FAC for components identified in these items. However, the steam generator program described in the GALL report only discusses corrosion of steam generator tubes; it does not discuss corrosion, pitting, ligament cracking or FAC for components identified in these items. Identify the methods of detecting general corrosion and pitting of the steam generator shell assembly that are discussed in Information Notice 90-14, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," January 26, 1990, and loss of section thickness due to FAC for reactor coolant system components identified in line Items 3.1.1.02, 3.1.1.16, 3.1.1.17, 3.1.2.06, and 3.1.2.14. In addition, confirm that the steam generator program identified in Item 3.1.1.15 is program B.2.9.

3.1.1-2 The GALL report indicates that the growth of intergranular separation (underclad cracks) in low alloy or carbon steel heat affected zones under austenitic stainless steel cladding is a TLAA to be evaluated for the period of extended operation for all the SA 508-CL2 forgings where the cladding was deposited with a high-heat-input welding process. The applicant indicates underclad crack growth due to cyclic loading was not identified as a TLAA for FCS.

Underclad cracks were observed in SA 508 Class 3 nozzles clad with multiple-layer, strip electrode, submerged-arc welding processes where preheating and post-heating were applied to the first layer but not to the subsequent layers. In order for the staff to determine whether this issue is a TLAA for FCS, provide the following information:

a. Identify any reactor vessel components that were fabricated from SA 508 Class 2 or 3 forgings.

b. Indicate whether any of the SA 508 Class 2 or 3 forgings identified above are susceptible to underclad cracking.

c. Indicate whether any of the SA 508 Class 2 or 3 forgings are subject to neutron embrittlement (i.e., subject to a neutron fluence greater than or equal to 1017 n/cm2 [E>1MeV]).

d. If any forgings are susceptible to underclad cracking, identify the basis for concluding that the cracks will not result in loss of reactor vessel integrity during the period of extended operation. The assessment should consider the impact of fatigue and neutron embrittlement on the underclad cracks.

3.1.1-3 LRA Table 3.1-1, row 3.1.1.09, indicates that crack initiation and growth due to SCC and PWSCC in PWR core support pads, instrument tubes (bottom head penetrations), pressurizer spray heads, and nozzles for the steam generator instruments and drains are managed by the Alloy 600 Program (LRA Section B.3.1). The application indicates that the Alloy 600 Program will be consistent with the requirements of XI.M11, "Nickel-Alloy Nozzles and Penetrations," as identified in NUREG-1801, prior to the period of extended operation. XI.M11 indicates the scope of the program is to include those components currently identified as susceptible to PWSCC and those that will be susceptible during the period of extended operation. On this basis, using the latest model for susceptibility of Alloy 600 components to PWSCC, identify all Alloy 600 components that are susceptible to PWSCC during the current license term and the period of extended operation, and identify the inspection methods to be used to detect PWSCC.

3.1.1-4 Programs identified in NUREG-1801 are generic programs. When components experience unusual aging effects, the programs identified in NUREG-1801 may not be applicable. CRD Housings (LRA Table 3.1-1, row 3.1.1.25) are identified as being susceptible to SCC and PWSCC with aging management provided by the inservice inspection program and water chemistry program. Cracking has been reported on CRD Housings at FCS (January 25, 2002, letter from OPPD) and Palisades (Nuclear Management Company letters to the NRC dated August 20, 2001, and March 14, 2002). The Palisades and FCS CRD housings have similar designs.

Because this operating experience was not considered in the development of the LRA, the staff requests the following information in order to understand how this experience impacts license renewal:

a. Identify the CRD locations, the materials and aging mechanisms that are responsible for the cracking in the CRD Housings at FCS and Palisades.

b. Identify any design, materials, and environmental factors that would preclude cracking of the type identified in a).

c. Identify how the cracks in Item a) were detected. Identify the current program and the frequency of examination required to ensure that the cracks in Item a) do not result in loss of CRD housing integrity. Were the cracks detected using NDE methods identified in the inservice inspection program?

Were alternative examination methods (methods not identified in the ASME Code) used to detect these cracks ?

d. As a result of the discussion above, will the inservice inspection program and water chemistry program be adequate for managing the aging effects discussed in Item a)? Provide the basis for this conclusion.

3.1.2-1 LRA Table 3.1-2, rows 3.1.2.04 and 3.1.2.05, indicates that the steam generator lower head, manway cladding, primary side tube sheet and reactor coolant pump thermal barrier are subject to cracking and the aging management program is the chemistry program. The chemistry program will, to some extent, mitigate cracking; but will not monitor cracking. Provide your basis for concluding monitoring of crack initiation and growth is not necessary for these components. If adequate justification is not provided, provide a program to monitor crack initiation and growth.

3.1.2-2 LRA Table 3.1-2, row 3.1.2.05, indicates that the CASS reactor coolant pump thermal barrier is subject to cracking. The staff believes that this component may also be subject to a reduction in fracture toughness from thermal embrittlement. Identify whether the CASS material is also subject to reduction in fracture toughness resulting from thermal embrittlement. If it is subject to thermal embrittlement, identify the program for managing this aging effect.

3.1.2-3 LRA Table 3.1-2, rows 3.1.2.08 and 3.1.2.11, indicates that void swelling, and reduction in fracture toughness of the reactor vessel internals flow skirt are managed by the reactor vessel internals inspection program and row 3.1.2.09 indicates that cracking of the reactor vessel internals flow skirt is managed by the Alloy 600 program. The Alloy 600 program is for piping and head penetrations and is dependent on leakage detection for detection of cracking. Identify the inspections and frequency of inspection to be performed as part of the Alloy 600 program to detect cracks in the reactor vessel internals flow skirt. Since the reactor vessel internals inspection program indicates that a fluence, stress, and fracture mechanics analysis will be performed to determine the critical location, acceptance criteria and appropriate inspection technique, confirm that the applicant is planning to perform these analyses for the reactor vessel internals flow skirt to manage the aging effects of void swelling and reduction in fracture toughness.

3.1.2-4 LRA Table 3.1.2, row 3.1.2.16, indicates cracking of pressurizer relief valve and instrument nozzle inserts are managed by the chemistry program and the inservice inspection program. Identify the inspections and frequency of inspection to be performed as part of inservice inspection program to detect cracks in the pressurizer relief valve and instrument nozzle inserts. Provide your basis for concluding these inspection will be adequate for detecting cracking in these components.

3.1.2-5 Components in Item 3.1.2.02 are subject to loss of material due to crevice corrosion. This aging effect is managed by the chemistry program. The chemistry program will, to some extent, mitigate crevice corrosion; but will not monitor crevice corrosion. Items in Table C1,and D2 in Section IV of GALL identify crevice corrosion as an aging effect and recommend water chemistry and an inservice inspection program to monitor this aging effect. In order to monitor whether crevice corrosion is occurring in the components listed in Item 3.1.2.02, identify an inspection program for these components that will monitor whether crevice corrosion is occurring.

3.1.2-6 Item 3.1.1.30 in LRA Table 3.1-1, “pressurizer integral supports”, states that the component identified in the GALL report is not applicable to FCS. The aging effect for pressurizer integral supports is identified as crack initiation and growth due to cyclic loading. The SRP indicates that the AMP for this aging effect is the inservice inspection program. LRA Table 2.3.1.2-1 indicates that the pressurizer support assembly is within scope. For this item, LRA Table 3.1-2, row 3.1.2.15 only discusses loss of material due to boric acid corrosion. The boric acid corrosion program will not detect cracks in pressurizer supports. Provide your basis for concluding that crack initiation and growth due to cyclic loading is not an applicable aging effect for the pressurizer support assembly. If it is applicable, provide an AMP for this aging effect.

3.1.3-1 LRA Table 3.1-3, row 03, “Bolt-Thermal Shield,” credits the inservice inspection program for managing loss of preload in the thermal shield bolts. As stated in the justification column of 3.1.3.03, the basis for crediting ISI is that the material, environment, and aging effects are the same as for components evaluated in Volume 2, IV.B3.4-h, of the GALL report. This section of the GALL report states that GALL programs XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD,” and XI.M14, “Loose Part Monitoring,” are credited with managing aging in the components similar to the thermal shield bolts. On page B-3 of the LRA, the applicant states that a loose parts monitoring program is not credited for license renewal at FCS. Instead, the reactor vessel internals program (RVII, LRA Section B.2.8) is credited with managing aging. The RVII program states that it is consistent with GALL program XI.M16, “PWR Vessel Internals,” with an exception that no augmented inspection of bolting is scheduled. This exception refers to bolting for the reactor vessel. In addition, the staff’s review of the operating experience discussed in LRA Section B.2.8 does not specifically discuss bolting for the thermal shield. In order to have reasonable assurance that the thermal shield bolting will be adequately managed during the period of extended operation, the staff requests the following information:

1. Identify plant-specific and industry operating experience with respect to cracking and loss of preload of thermal shield bolts. Identify how the proposed program for thermal shield bolts will ensure bolting integrity.

2. GALL Chapter XI.M16, “PWR Vessel Internals” states, under the subsection discussing the detection of aging effects, “For bolted components, augmented ISI is to include other demonstrated acceptable inspection methods to detect cracks between the bolt head and the shank. Alternatively, the applicant may perform a component-specific evaluation, including a mechanical loading assessment to determine the maximum

tensile loading on the component during ASME Code Level A, B, C, and D conditions. If the loading is compressive or low enough (<5 ksi) to preclude fracture, then supplemental inspection of the component is not required. Failure to meet this criterion requires continued use of the augmented inspection methods." Will the thermal shield bolt program satisfy this inspection/analysis?

3.2 Engineered Safety Features

3.2-1 The staff's expectation is that every component that is identified as requiring an AMR in LRA Tables 2.3.2.1-1 and 2.3.2.2-1, would have a link to AMR Table 3.2-1, 3.2-2, or 3.2-3 in the LRA. However, during its review, the staff found links to other system groups. Each link to a non-ESF system group is identified below. For each item, please provide a justification for the link, or provide the correct link to LRA Table 3.2-1, 3.2-2, or 3.2-3:

Component	Table	Link
Heat Exchanger	2.3.2.1-1	3.3.2.74 (Auxiliary system link)
Pipe & Fittings	2.3.2.1-1	3.3.2.10 (Auxiliary system link) 3.3.2.17 (Auxiliary system link) 3.3.2.18 (Auxiliary system link)
Heat Exchanger	2.3.2.2-1	3.3.2.76 (Auxiliary system link) 3.4.1.10 (SPCS link)
Pipes & Fittings	2.3.2.2-1	3.4.1.02 (SPGS link) 3.4.1.05 (SPGS link) 3.4.1.06 (SPGS link) 3.4.1.13 (SPGS link)
Valve Bodies	2.3.2.2-1	3.4.1.02 (SPGS link) 3.4.1.05 (SPGS link) 3.4.1.06 (SPGS link) 3.4.1.13 (SPGS link)

3.2.1-1 LRA Table 3.2-1, row 3.2.1.04, states in the "Discussion" column, that no FCS containment isolation valves (CIVs) and associated piping, in systems that are not addressed in this or other sections of this application were determined to be subject to the aging effect of loss of material due to microbiologically influenced corrosion (MIC). This statement is not clear. To determine whether these components are applicable to FCS and to assess the adequacy of the management of the aging effects associated with these components, please clarify what the statement means. Specifically, because LRA Table 3.2-1 originates from the GALL report, please clarify whether CIVs and associated piping at FCS are managed in accordance with the GALL report. If so, please discuss the evaluation that is recommended in GALL, including the associated aging management program(s) credited for managing loss of material due to MIC in these components.

3.2.1-2 LRA Table 3.2-1, Row Number 3.2.1.12, indicates that for closure bolting in high pressure or high temperature systems, bolting integrity is the aging management program for the identified aging effects of loss of material due to general corrosion, loss of preload due to stress relaxation, and crack initiation and growth due to cyclic loading or stress corrosion cracking (SCC). The applicant stated in LRA Appendix B that the FCS bolting integrity program (LRA Section B.1.1) is consistent with XI.M18, "Bolting Integrity," as identified in NUREG-1801 with the following exception: "FCS has not identified stress corrosion cracking (SCC) as a creditable aging effect requiring management for high strength carbon steel bolting in plant indoor air. FCS will utilize ASME Section XI, Subsection IWF visual VT-3 inspection requirements rather than volumetric inspections for inspection of supports."

The applicant is requested to provide a basis on which to conclude that SCC will not have to be considered as a creditable aging effect requiring management, considering the potentially high pressure or high temperature environment of moisture, humidity, and leaking fluid. Also, in view of the examination methods specified in XI.M18, which include VT-1 and volumetric examination as methods of inspection, in accordance with the requirements of Section XI, Subsections IWB and IWC, the applicant is requested to address the adequacy of using VT-3 visual examination of Subsection IWF, to detect the above identified aging effects of loss of material, loss of preload, and cracking.

3.2.1-3 In LRA Table 2.3.2.1-1, for heat exchanger, Row Number 3.2.3.01 is listed under Aging Management Review Results. In LRA Table 3.2-3, Row Number 3.2.3.01 is shown to cover such components as safety injection tanks, flow element and orifice bodies, orifice plate, tubing and heat exchangers. Also, Row Number 3.2.1.10 is referenced under the applicable NUREG-1801 Aging Management Review Results. In a review of NUREG-1801 (Vol. 1) Table 2, and NUREG-1801 (Vol. 2), Chapter V, however, the staff failed to identify heat exchanger as a component to be linked to Row Number 3.2.1.10. The applicant is requested to discuss this apparent discrepancy, and provide the correct justification for crediting the GALL program AMR for managing aging in the safety injection and containment spray heat exchangers.

3.2.3-1 In LRA Table 3.2-3, if the terms, “safety injection tank” and “accumulator”, are used interchangeably for FCS, explain why FCS safety injection tanks (cf. Row Number 3.2.3.01) are associated with the material of stainless steel, whereas accumulators (cf. Row Number 3.2.3.02) are associated with carbon steel with stainless steel cladding, for the same kind of environment.

3.2.3-2 In LRA Table 3.2-3, row 3.2.3.02, based on the review results of the GALL report, for leakage accumulators (or safety injection tanks) with leaking chemically treated borated water, the corresponding FCS AERMs should be loss of material/boric acid corrosion, instead of crack initiation and growth/stress corrosion cracking. Also, according to Volume 2, V.D1.7-a of the GALL report, the aging management program to be relied on for this aging effect should be Chapter XI.M10, “Boric Acid Corrosion,” instead of Chapter XI.M2, “Water Chemistry,” as required by V.D1.7-b. Explain the discrepancies.

3.3 Auxiliary Systems

3.3-1 The staff’s expectation is that every component that is identified as requiring an AMR in LRA Tables 2.3.3.1-1 through 2.3.3.20-1, would have a link to AMR Table 3.3-1, 3.3-2, or 3.3-3 in the LRA. However, during its review, the staff found links to other system groups. Each link to a non-auxiliary system group is identified below. For each item, please provide a justification for the link, or provide the correct link to LRA Table 3.3-1, 3.3-2, or 3.3-3:

Component	Table	Link
Heat Exchanger	2.3.3.1-1	3.4.1.10 (SPCS link)
Valve Bodies	2.3.3.1-1	3.1.1.25 (Reactor system link) 3.4.1.02 (SPCS link)
Filter/Strainer Housing	2.3.3.2-1	3.2.1.10 (ESF system link)
Heat Exchanger	2.3.3.2-1	3.2.1.10 (ESF system link) 3.4.1.10 (SPCS link)
Ion Exchanger	2.3.3.2-1	3.2.1.10 (ESF system link)
Pipes & Fittings	2.3.3.2-1	3.2.1.10 (ESF system link)
Pump Casings	2.3.3.2-1	3.2.1.10 (ESF system link)
Valve Bodies	2.3.3.2-1	3.2.1.10 (ESF system link)
Pipes & Fittings	2.3.3.10-1	3.1.3.13 (Reactor system link)
Valve Operators	2.3.3.10-1	3.1.3.13 (Reactor system link)
Heat Exchanger	2.3.3.19-1	3.4.1.10 (SPCS link)
Pipes & Fittings	2.3.3.19-1	3.1.1.01 (Reactor system link)

Valve Bodies	2.3.3.19-1	3.1.1.01 (Reactor system link)

3.3-2 Numerous tables included in the application list the component material and the environment to which the component is exposed. However, the applicant did not provide a description of these environments in the LRA. It should be noted that aging effect depends on the component material as well as the plant specific environment characteristic. For example, aging effect of component exposed to air environment is dependent, in part, on the type of air, the temperature, the oxygen content, and the water content (humidity), etc. The applicant is requested to provide a description of these environments included in the LRA.

3.3.1-1 Numerous ventilation systems discussed in LRA Section 2.3 include elastomer components in the system. Normally ventilation systems contain elastomer materials in duct seals, flexible collars between ducts and fans, rubber boots, etc. For some plant designs, elastomer components are used as vibration isolators to prevent transmission of vibration and dynamic loading to the rest of the system. In LRA Table 3.3-1, Row Number 3.3.1.02, the applicant identified the aging effects of hardening, cracks, and loss of strength due to elastomer degradation, and loss of material due to wear for these elastomer components. To manage these aging effects, the applicant relied on its general corrosion of external surfaces program, described in LRA Section B.3.3. The description for this program identifies loss of material and cracking as plausible aging effects. The applicant stated that these aging effects can be detected by visual observation and inspection of external surfaces performed at intervals based on previous inspections and industry experience. The applicant is requested to clarify the discrepancy between LRA Table 3.3-1, Row Number 3.3.1.02 and LRA Section B.3.3 regarding the aging effects of concern. Specifically, the applicant is requested to clarify whether hardening and loss of strength are considered in the general corrosion of external surfaces program, and how these aging effects will be detected and managed using this program. In addition, the applicant is requested to provide the frequency of the subject inspection described in LRA Section B.3.3 for the applicable elastomer components, including a discussion of the operating history to demonstrate that the applicable aging degradations will be detected prior the loss of their intended function.

3.3.1-2 Numerous components included in LRA Tables 2.3.3.7-1 and 2.3.3.8-1 referred to LRA Table 3.3-2, Row Number 3.3.2.23, for the aging management review results. These components are made of carbon steel and are exposed to the internal environment of instrument air. The LRA states that there are no aging effects that require management for this material/environment combination. Similarly, in LRA Table 3.3.1, Row Number 3.3.1.18, the applicant stated that the components in the instrument air system at FCS are exposed to dry air and the environment (wet air/gas) identified in NUREG-1801 is not applicable to FCS. It should be noted that in the instrument air system, components that are located upstream of the air dryers are generally exposed to a wet air/gas environment and, therefore, may be subject to loss of material due to general and pitting corrosion. In addition, it is reasonable to assume that components downstream of the dryers are exposed to dry air/gas environment. However, this may not be supported by some operating experience. For example, NRC IN 87-28, “Air Systems Problems at U.S. Light Water Reactors,” provides the following: “A loss of decay heat removal and significant primary system heat up at Palisades in 1978 and 1981 were caused by water in the air system.” This experience implies that the air/gas system downstream of the dryer may not be dry. On the basis of this industry experience, the applicant is requested to discuss its plant-specific operating experience related to components that are exposed to an instrument air environment, and to provide a technical basis for not identifying loss of material as an aging effect for these components.

3.3.1-3 In LRA Table 3.3-1, Item 3.3.1.03, under *Discussion*, it states that the FCS aging management review (AMR) results are consistent with those reviewed and approved in NUREG-1801 for the chemical and volume control and primary sampling systems. There is no similar discussion related to the load handling system, yet LRA Section 2.4.2.5 credits this item for the load handling system. Discuss the AMR results of the load handling system, or justify its exclusion.

3.3.1-4 In LRA Table 3.3-1, Item 3.3.1.06 for components in the RCP oil collection system credits AMP B.3.5, “One Time Inspection Program,” for further evaluation of aging effects; however, AMP B.3.5 does not refer to Item 3.3.1.06. Please clarify.

3.3.1-5 In LRA Table 3.3.1-1, Item 3.3.1.09 for neutron absorbing sheets in spent fuel storage racks credits AMP B.2.7, “Periodic Surveillance and Preventative Maintenance (PM) Program,” to manage the aging; however, AMP B.2.7 does not list the spent fuel storage racks. Please clarify.

3.3.1-6 For the bolting in several of the auxiliary systems, the LRA cites Item 3.3.1.05, which is for “components in ventilation systems, diesel fuel oil system, and emergency diesel generator systems; external surfaces of carbon steel components.” Item 3.3.1.05 is for managing general loss of material, and credits AMP B.2.7, “Periodic Surveillance and Preventative Maintenance,” AMP B.3.3, “General Corrosion of External Surfaces,” and AMP B.2.5, “Fire Protection Programs.” However, the staff believes a more appropriate GALL reference for the management of bolting would be Item 3.3.1.23, which is for “closure bolting.” Item 3.3.1.23 addresses the loss of material and crack initiation and growth in bolting, and credits AMP B.1.1, “Bolting Integrity Program.” Explain why the bolting integrity program is not being used to manage bolt aging in these systems.

3.3.1-7 In LRA Table 2.3.3.4-1 for the emergency diesel generator lube oil and fuel oil system, the only material cited for the flexible hose is carbon steel. Many types of hoses rely on elastomers or other materials for the pressure boundary. Clarify whether the carbon steel provides the pressure boundary for the flexible hose in this system, and whether there are other materials in the hose that require aging management.

3.3.1-8 In LRA Table 2.3.3.13-1, the applicant identified loss of material as a plausible aging effect for ducts and fittings. The staff noted that for ducts in other ventilation systems, the applicant has also identified aging effects related to the elastomer degradation. In order for the staff to understand whether aging effects are applicable to elastomers in the ducts for the ventilating air system, the staff requests the applicant to clarify whether there are elastomer components in the ventilating air system and to provide a technical basis for not considering aging degradation of the elastomer component, if any.

3.3.1-9 For the hose cabinet identified in LRA Table 2.3.3.14-1, the LRA cites Item 3.3.1.13, which is credited for managing loss of material due to boric acid corrosion of carbon steel. Clarify whether this is due to the hoses' proximity to a system containing boric acid. If not, provide the basis for citing 3.3.1.13 for managing hose aging.

3.3.1-10 In LRA Table 2.3.3.14-1, Item 3.3.1.20 is credited for managing aging in the fire water pump casings. LRA Table 3.3-1, row 3.3.1.20 specifies raw water as the environment requiring aging management. Presumably this is the internal environment of the pump casing. Describe the external environment of the pump casing, and any required aging management.

3.3.1-11 In LRA Table 2.3.3.16-1, under pump casings, the LRA cites Item 3.3.1.24, which is for leaching of cast iron or bronze in raw water or soil. These environments do not appear consistent with the description of the component cooling water system in the LRA or the USAR. Please clarify the environments.

3.3.1-12 LRA Table 2.3.3.17-1 appears to only address the external environment of the components. Describe the internal environments, AERMs, and aging management for the components in the liquid waste disposal system.

3.3.1-13 For pipes and fittings in LRA Table 2.3.3.17-1, the LRA refers to carbon steel and stainless steel in a concrete environment (LRA Table 3.3-2, Items 3.3.2.22, 3.3.2.26, and 3.3.2.65) and concludes that there are no applicable aging effects. Industry experience has shown that carbon steel can degrade in a concrete environment. Provide additional information on the concrete environment to demonstrate that there are no applicable aging effects, or provide a program to manage aging of these pipes and fittings.

3.3.1-14 LRA Table 2.3.3.28-1 states that the gaseous waste disposal heat exchanger is exposed to "oxygenated treated water up to 200 degrees". The staff believes that the system pipes and fittings are also exposed to this environment, yet this environment is not identified for the pipes and fittings. Clarify whether the system pipes and fittings are exposed to this environment. If so, discuss the programs that will manage aging for these components.

3.3.1-15 The staff noted discrepancies in the tables in LRA Sections 2 and 3. Please clarify the following, as necessary:

1. For numerous components in the CVCS (see LRA Table 2.3.3.1-1), the LRA cites Item 3.3.1.08, which is for heat exchangers. Provide justification for why components other than the heat exchangers can be managed using programs intended to manage aging in the heat exchangers.

2. For the CVCS heat exchangers (see LRA Table 2.3.3.1-1), the LRA cites Item 3.3.1.05, which has no relation to heat exchangers (this AMR is for managing components in ventilation systems, diesel fuel oil, and emergency diesel systems, as well as the external surfaces of carbon steel components). Provide justification for crediting AMR 3.3.1.05 for managing aging in the heat exchangers.

3.3.2-1 LRA Table 3.3.2, row number 3.3.2.77 (which applies to the raw water system filter/strainer housing), identifies the periodic surveillance and preventive maintenance program as the applicable aging management program to manage aging of the filter/strainer housing. However, LRA Section B.2.7, "Periodic Surveillance and Preventive Maintenance Program," of the LRA does not include the raw water system within the scope of this aging management program. Please explain why the raw water system is not included in the scope of the periodic surveillance and preventive maintenance program, include this system in the program, or identify an alternate program to manage the identified aging effect.

3.3.2 -2 For bolting, the LRA cites Item 3.3.2.64, which is for stainless steel in ambient air. This implies that there is stainless steel bolting in the CVCS. This system carries borated water, and there is the potential for boric acid leaks at bolted connections. Clarify whether there is a potential for boric acid to leak on the stainless steel bolting in the CVCS. If so, discuss whether the bolting temperature and tension are sufficient to initiate SCC in the bolting, and discuss the aging management of the stainless steel bolting. (Note, this question also applies to other systems, such as spent fuel pool cooling.) Also, discuss whether GALL AMP XI.M18, "Bolting Integrity," would apply to the management of bolt aging in the CVCS.

3.3.2-3 LRA Table 3.3-2, credits AMR Item 3.3.2.44 for the management of copper alloys above ground, buried in gravel, and protected from the elements. Item 3.3.2.44 credits AMP B.2.3, "Diesel Fuel Monitoring and Storage Program," to manage the external loss of material. Similarly, the LRA credits B.2.3 in Items 3.3.2.21 and 3.3.2.47 for aging management of pipes and fitting in these environments. AMP B.2.3 is based on GALL program XI.M30, "Fuel Oil Chemistry," and, as such, focuses on the internals of components subjected to oil environments. The staff does not understand how an AMP that is credited in GALL for managing aging of component internals in an oil environment can also be credited for managing loss of material for components above ground, buried in gravel, and protected from the elements. Please clarify the aging management of the external surfaces of these components.

3.3.2-4 In LRA Table 2.3.3.10-1, the applicant identified two intended functions, heat transfer and pressure boundary, for the heat exchanger, and referred to LRA Tables 3.3-1, 3.3-2, and 3.3-3; rows 3.3.1.05, 3.3.2.10, 3.3.2.39, and 3.3.3.09 for the aging management review results for the heat exchanger. In LRA Table 3.3-2, row 3.3.2.39, the applicant identified loss of material as the applicable aging effect and credited the chemistry program and cooling water corrosion program for managing the aging effect. However, the staff notes that fouling is another aging effect that will result in a loss of the intended function of heat transfer. The applicant is requested to provide a technical basis for not identifying fouling as an applicable aging effect for the heat exchanger that has an intended function of heat transfer, or provide a program to manage fouling in the heat exchanger.

3.3.2-5 In LRA Table 2.3.3.12-1, the applicant identified two intended functions, heat transfer and pressure boundary for the heat exchanger, and referred to LRA Tables 3.3-1 and 3.3-2, rows 3.3.1.05, 3.3.2.29, 3.3.2.39, and 3.3.2.40, for the aging management review results for the heat exchanger. In LRA Table 3.3-2, rows 3.3.2.29 and 3.3.2.39, the applicant identified loss of material as the applicable aging effect and credited chemistry program and cooling water corrosion program for managing the aging effect. However, the staff notes that fouling is another aging effect that will result in a loss of the intended function of heat transfer. The applicant is requested to provide a technical basis for not identifying fouling as an applicable aging effect for this heat exchanger, or provide a program to manage fouling in the heat exchanger.

3.3.2-6 For piping, LRA Section 2.3.3.14 cites Items 3.3.2.34 and 3.3.2.35 in LRA Table 3.3-2 for aging management. These items cover buried concrete pipes and concrete pipes exposed to raw water. Both of these items conclude that there are no aging effects requiring management. The staff believes that concrete exposed to raw water is subject to aging degradation and requires aging management. Similarly, buried concrete is subject to aging degradation unless the soil environment is benign. On this basis, provide justification for why concrete components in these environments do not have aging effects that require management, or provide a program to manage the aging for the buried concrete pipe carrying raw water for the fire protection system.

3.3.2-7 The staff noted discrepancies in the tables in LRA Sections 2 and 3. Please clarify the following, as necessary:

1. LRA Table 3.3-2, Item 3.3.2.81 covers components used to handle fuel; however, the LRA does not consider fuel handling equipment to be part of the auxiliary systems. This item belongs in the tables in LRA Section 3.5. Provide justification for including these components in the auxiliary system table.

2. In LRA Table 2.3.3.4-1 (emergency diesel generator lube oil and fuel oil) for filters/strainers, the application cites LRA Table 3.3-2, Item 3.3.2.85 for managing aging of these components. However, 3.3.2.85 is credited for managing aging in heat exchanger tubes and valves. Provide justification for why this AMR can be credited with managing the emergency diesel generator lube oil and fuel oil system filters/strainers.

3. LRA Table 2.3.3.4-1 credits Item 3.3.2.21, for managing aging of the emergency diesel generator lube oil and fuel oil tanks. However, LRA Table 3.3-2 credits this AMR with managing aging in pipes and fittings, not tanks. Provide justification for crediting 3.3.2.21 for managing aging in tanks.

4. For the raw water system (LRA Table 2.3.3.15-1), under Valve Bodies, the LRA cites Item 3.3.2.76, which LRA Table 3.3-2 credits for managing aging in the heat exchanger tubes exposed to oxygenated, treated water. Provide justification

for crediting 3.3.2.76 for managing aging in valve bodies in the raw water system.

3.3.3-1 For several components in the auxiliary systems, the applicant referred to LRA Table 3.3-3, Row Number 3.3.3.09 for the aging management review results for these components. In that table, the applicant identified "ambient air" as the environment and credited the boric acid corrosion prevention program for managing the aging effect. The applicant also referred to Row Number 3.3.1.13 of LRA Table 3.3-1 as the applicable NUREG-1801 aging management review results. The staff noted that the referred NUREG-1801 item addresses aging effects for the component group in air exposed to leaking and dripping borated treated water. The applicant is requested to clarify that "boric water leaks" rather than "ambient air" is the environment characteristic of concern.

3.3.3-2 In LRA Table 3.3-3, Item 3.3.3.03 credits the AMR results in LRA Table 3.4-1, Item 3.4.1.02 based on use of the same materials, environments, and AERMs, as GALL VII.G.4-b; however, Item 3.4.1.02 (and GALL VII.G.4-b) credits the chemistry program and one time inspection program to manage aging, while Item 3.3.3.03 does not call for a one time inspection. Please clarify whether a one-time inspection is credited with managing aging for the components in LRA Item 3.3.3.03, or justify its exclusion.

3.3.3-3 In LRA Table 3.3-3, Item 3.3.3.04 credits the AMR results in LRA Table 3.3-1, Item 3.3.1.08 based on similar materials, environments, AERMs, and aging management to GALL VII.E1.7-c. However, GALL VII.E1.7-c (and Item 3.3.1.08) credits the chemistry program and one-time inspection program to manage aging, while Item 3.3.3.04 only calls for the chemistry program. Please clarify whether a one-time inspection is credited with managing aging for the components in LRA Item 3.3.3.04, or justify its exclusion.

3.3.3-4 LRA Table 3.3-3, Item 3.3.3.08, used for heater sleeves, cites GALL AMRs VII.H2.1-a and VII.C2.5-a. These GALL AMRs are for diesel generator cooling water subsystem components (cooled by closed-cycle cooling water) with water temperature less than 90 ^{o}C and for flow orifice bodies in treated water with water temperature less than 35 ^{o}C, respectively. The applicability of these GALL AMRs to aging management of the heater sleeves is unclear to the staff. In order to determine whether these GALL AMRs can effectively manage aging in the heater sleeves, the staff requests the applicant to discuss the temperature of the heater sleeves and the applicability of the GALL programs to the aging management of heater sleeves. If the heater sleeve temperature exceeds the above limits, justify the use of the GALL programs and discuss the need for further evaluation of aging effects of components that use Item 3.3.3.08.

3.3.3-5 In LRA Table 3.3-3, Item 3.3.3.10 credits the AMR results in LRA Table 3.3-1, Item 3.3.1.05 based on use of the same materials, environments, and AERMs, and aging management as GALL VII.F2.1-a; however, Item 3.3.3.05 credits the periodic surveillance and preventative maintenance program and the general corrosion of external surfaces program to manage aging, while Item 3.3.3.10 only calls for the periodic surveillance and preventative maintenance program. Please clarify whether the general corrosion of external surfaces program is credited with managing aging for the components in LRA Item 3.3.3.10, or justify its exclusion.

3.3.3-6 The staff noted discrepancies in the tables in LRA Sections 2 and 3 of the LRA. Please clarify the following, as necessary:

1. LRA Table 3.3-3, Item 3.3.3.01 refers to Item 3.3.1.10 based on the use of GALL V.D1.1-a; however, Item 3.3.1.10 does not cover GALL V.D1.1-a. Item 3.3.1.10 is credited with managing aging in the new fuel rack assembly, while GALL Section V.D1.1-a discusses aging management for piping and fittings in emergency core cooling systems. The GALL reference appears to be correct for managing aging for components in Item 3.3.3.01, but 3.3.3.01 also credits 3.3.1.10, which seems to be incorrect. Please resolve the discrepancy.

2. LRA Table 3.3-3 credits item 3.3.3.03 for managing aging in pipes and fittings; however, it is also credited in Table 2.3.3.1-1, "CVCS," for aging management of valve bodies. Further, the LRA states that GALL AMR 3.4.1.02 is applicable for managing pipes and fittings. However, Item 3.4.1.02 in LRA Table 3.4-1, states that this AMR is credited with managing aging for carbon steel in treated water, while Item 3.3.3.03 is for stainless steel. Further, Item 3.3.3.03 states it is for the same materials, environments, AERMs, and aging management as GALL VIII.G.4-b; however, GALL VIII.G.4-b is for condensate storage tank components under different conditions than described in Item 3.3.3.03. Please resolve these discrepancies.

3. Item 3.3.3.09 in LRA Table 3.3-3, includes copper alloy, and credits Item 3.3.1.13 for managing aging of the components associated with 3.3.3.09 (valve bodies, piping and fittings, duct, damper, bolts, and heat exchangers made of cast iron, cadmium-plated steel, galvanized steel, or copper alloy in ambient air). However, Item 3.3.1.13 is credited only for boric acid corrosion of carbon and low alloy steel. Please resolve the discrepancy.

3.4 Steam and Power Conversion Systems

3.4-1 The staff's review of LRA Section 3.4 found that aging effects associated with two types of materials jointed together, such as carbon steel jointed with stainless steel, are not discussed. Do any components in the steam and power conversion systems consist of dissimilar metals? Can they be subject to loss of material due to galvanic corrosion? If so, identify these components and describe how the aging effects due to galvanic corrosion are managed during the period of extended operation, or provide justification for why loss of material due to galvanic corrosion is not a plausible aging effect.

3.4-2 The staff cannot discern internal from external environments in the LRA. Therefore, the staff requests the applicant to confirm that raw water is not an internal or external environment that steam and power conversion system components are exposed to. If any components in the steam and power conversion systems are exposed to raw water, identify the system, components, aging effects, and aging management programs credited with managing the aging effects.

3.4.1-1 In LRA Table 3.4-1, row number 3.4.1.12, it states that the external surfaces of buried condensate storage tank and AFW piping identified in the GALL report is not applicable to FCS. The staff needs to understand the basis for the applicant's conclusion that this GALL item is not applicable to FCS. Does this mean that there are no buried tanks or piping in the steam and power conversion systems at FCS, or are there no plausible aging effects for these components? Please clarify the basis for the conclusion.

3.4.1-2 Industry operating experience has identified cracking from mechanical vibration as a potential aging effect for the piping system components in the steam and power conversion systems. Given this experience, please explain why mechanical vibration is not identified as an applicable aging effect for components in the steam and power conversion systems.

3.4.1-3 LRA Table 3.4-1, row 3.4.1.08, discusses aging management of closure bolting, and credits the bolting integrity program (LRA Section B.1.1) for managing loss of material and crack initiation, with one exception. LRA Section B.1.1 states that the bolting integrity program will be consistent with GALL program XI.M3, "Reactor Head Closure Studs" and XI.M18, "Bolting Integrity," with the exception that SCC has not been identified as a creditable aging effect for high-strength carbon steel bolting in plant indoor air. The reviewer requests the applicant to discuss the basis for its conclusion that SCC is not a creditable aging effect for bolting.

3.4.1-4 It is stated in LRA Table 3.4-1, row number 3.4.1.03, that the environment identified in NUREG-1801 is not applicable to FCS, since the AFW piping at FCS is not exposed to untreated water from a back-up water supply. It appears that AFW piping from the emergency feedwater storage tank (EFWST) is exposed to a ground water, soil and /or outdoor environment and would fall in the category identified in the NUREG-1801. Since there is no reference to the buried piping program for the AFW piping in LRA Section 2.3.4.2-1 for the AFW piping, provide clarification as to how the aging effects in this portion of the AFW piping will be managed.

3.4.1-5 It is stated in LRA Table 3.4-1, row number 3.4.1.05, that the group includes carbon and low alloy steel in ambient air. The statement implies that other materials and environments are covered in this group. Please identify those materials and environments. Also, for the ambient air environment, provide the range of humidity and moisture content.

3.4.1-6 LRA Tables 2.3.1.1-1 and 2.3.4.2-1 identify components, intended functions, and aging management review results for the feedwater and the AFW systems, respectively. Item 3.4.1.08 in the AMR results column for bolting in these systems leads to the aging management of loss of material due to general corrosion, crack initiation, and growth due to cyclic loading and/or SCC in closure bolting in LRA Table 3.4-1. The aging effect is stated to be managed by the bolting integrity program. However, the scope of this program as discussed in LRA Section B.1.1, does not include LRATables 3.4-1, 3.4-2, or 3.4-3. Provide clarification for this discrepancy.

3.4.1-7 LRA Tables 2.3.4.1-1 (Feedwater), 2.3.4.2-1 (Auxiliary Feedwater), and 2.3.4.3-1 (Main steam and Turbine steam extractions) identify Item 3.4.1.13 for AMR results of bolting. In LRA Table 3.4-1, row number 3.4.1.13, it is stated that the boric acid corrosion prevention program would manage the aging effect of loss of material due to boric acid corrosion in bolting. However, the steam and power conversion system has not been identified as being within the scope of the boric acid corrosion program, as discussed in LRA Section B.2.1. Provide clarification for this discrepancy.

3.4.1-8 In LRA Tables 2.3.4.3-1 (Main Steam and Turbine Steam Extraction) and 2.3.4.1-1 (Feedwater), AMR results for pipe/fittings refer to item 3.4.1.06. This link in LRA Table 3.4-1, row 3.4.1.06 identifies FAC as the AMP for carbon steel piping. However, the scope of the FAC program in LRA Section B.1.5 does not refer to LRA Table 3.4-1, implying that carbon steel piping in main steam and turbine steam extraction and feedwater is not covered by the FAC program. Please clarify this discrepancy. Similarly, link 3.4.3.04 in LRA Table 2.3.4.3-1 identifies the FAC program for managing the aging effects in carbon steel piping/fittings in LRA Table 3.4-3. This indicates that some portions of the piping/fittings in main steam and turbine steam extraction are evaluated in NUREG-1801 and some are not, but are still managed by the FAC program due to similarity of materials and environments. Identify the specific portions of the piping which are evaluated in GALL, and which are not.

3.4.1-9 LRA Table 2.3.4.2-1, which lists components subject to AMR for the auxiliary feedwater system, refers to items 3.4.1.02 and 3.4.1.05 for AMR results for tanks. These links in LRA Table 3.4-1 lead to the chemistry program (B.1.2), one-time inspection program (B.3.5), and general corrosion for external surfaces program (B.3.3). However, the one-time inspection program (B.3.5) does not have LRA Table 3.4-1 within its scope and, therefore, excludes tanks in the auxiliary feedwater system. Provide clarification for this discrepancy.

3.4.1-10 In LRA Table 2.3.4.2-1, the aging management review results for heat exchangers are identified as 3.4.2.3, 3.4.2.4, 3.4.2.5 and 3.4.2.6. These links in LRA Table 3.4-2 have no reference to the closed and open cycle cooling system programs as recommended in NUREG-1801, Volume 2, XI.M20, “Open-Cycle Cooling Water System,” and XI.M21, “Close-Cycle Cooling Water System.” Provide justification to show that the AMP at FCS will provide equivalent aging management for the heat exchangers in the AFW system at FCS.

3.4.1-11 With regard to the one-time inspection and the water chemistry programs, GALL recommends inspection of stagnant areas based on severity of condition, time of service, and lowest design margin. Identify these worst-case locations for components in the feedwater, AFW, and main steam and turbine steam extraction systems which utilize these programs.

3.4.1-12 Flow element/orifice housings are not proposed to be managed for FAC in the LRA. In the staff’s experience, these components are sometimes made of carbon steel and, therefore, may be susceptible to FAC. Please confirm that the steam and power conversion systems do not contain flow elements or orifice housings made of carbon steel. If the steam and power conversion systems contain flow elements and orifice housings made of carbon steel, please provide a justification for why these components are not subject to this aging effect, or provide a discussion of how this aging effect will be managed for these components.

3.4.1-13 In LRA Table 3.4-1, row number 3.4.1.01 relates to cumulative fatigue damage of piping and fittings, which is managed by a TLAA, as specified in NUREG-1801, Volume 2, VIII.G-.1-b. for auxiliary feedwater piping. Is this for the entire AFW system, or just a portion of the system? Note that for the MS and feedwater systems, GALL line item VIII.D1.1-b, specifies that only a portion of the piping can utilize a TLAA.

3.4.1-14 The piping and fittings in the feedwater system are subject to wall thinning due to flow accelerated corrosion as indicated in LRA Tables 2.3.4-1 and 3.4-1, row 3.4.1.06. This aging effect is managed by the FAC program in LRA Appendix B.1.5. However, the scope of this program does not include LRA Table 3.4-1, indicating that piping and fittings in the feedwater system are excluded from the FAC program. Provide clarification for this discrepancy. Also, NUREG-1801, Volume 2, VIII D2.3-a and VIII D2.3.2 recommends the FAC program for the feedwater pump (steam turbine and motor driven) suction and discharge lines. Clarify the exclusion of these components from LRA Table 2.3.4-1.

3.4.3-1 The FAC Program (LRA Section B.1.5) is intended to be used for filters/strainers (refer to row number 3.4.3.04, Table 3.4-3 of the LRA) because it is stated to have the same material, exposed to the same environment, and is subject to the same aging effects as the components evaluated in NUREG-1801, Volume 2, VIII B1.1-C, which are piping/fitting elbows and valve bodies. The FAC program is an analytical, inspection, and verification program in which the component geometry and hydrodynamic conditions play an important role in the analysis. Since the geometry and hydrodynamic conditions of filters and strainers are substantially different from piping/fittings and valve bodies, explain how the predictive methodology of the FAC program will be applied to filters and strainers.

3.4.3-2 Discuss how the boric acid corrosion program would manage the aging effect of loss of material due to boric acid corrosion for filters and strainers such that the intended function of filtration is maintained, since even an acceptable level of corrosion from a structural integrity point of view could degrade the intended function of filtration.

3.5 Structures

3.5-1 Each row entry in LRA Table 3.5-1 identifies an aging management program for each aging effect/mechanism in the table. However, for many of the row entries in LRA Table 3.5-1, the ‘Discussion’ column concludes that the aging effect/mechanism is not applicable for the component(s) at FCS. Although the aging effect/mechanism may not have been observed to date at FCS, the staff considers the inspection for that aging effect during the period of extended operation through an aging management program to be appropriate in many cases. Provide clarification as to whether the aging effects, identified for the following row entries in

LRA Table 3.5-1, will be managed during the period of extended operation by the aging management program that is listed with the row entry:

Row Entry	Aging Management Program
3.5.1.07	Containment ISI
3.5.1.10	Plant specific
3.5.1.12	Containment ISI and Containment Leak Rate Test
3.5.1.16	Structures Monitoring
3.5.1.17	Plant specific
3.5.1.22	Plant specific

3.5-2 The staff's expectation is that every component that is identified as requiring an AMR in LRA Tables 2.4.1-1 through 2.4.2.7-1, would have a link to AMR Table 3.5-1, 3.5-2, or 3.5-3 in the LRA. However, during its review, the staff found links to other system groups. Each link to a non-structures group is identified below. For each item, please provide a justification for the link, or provide the correct link to LRA Table 3.5-1, 3.5-2, or 3.5-3:

Component	Table	Link
Calcium Silicate Board in Ambient Air	2.4.1-1	3.3.2.80 (Auxiliary system link)
Auxiliary Bldg Fire Penetration Barriers	2.4.2.1-1	3.3.1.19 (Auxiliary system link) 3.3.1.25 (Auxiliary system link) 3.3.2.51 (Auxiliary system link) 3.3.2.52 (Auxiliary system link) 3.3.2.53 (Auxiliary system link) 3.3.2.54 (Auxiliary system link) 3.3.2.79 (Auxiliary system link)
Auxiliary Bldg Pyrocrete	2.4.2.1-1	3.3.2.59 (Auxiliary system link) 3.3.2.60 (Auxiliary system link) 3.3.2.61 (Auxiliary system link)

Safety Injection and Refueling Water Tank	2.4.2.1-1	3.3.2.36 (Auxiliary system link)
Carbon Steel Pipe and Pipe Casing	2.4.2.3-1	3.3.1.05 (Auxiliary system link)
Fire Protection Pyrocrete	2.4.2.3-1	3.3.2.59 (Auxiliary system link) 3.3.2.60 (Auxiliary system link) 3.3.2.61 (Auxiliary system link)
Stainless Steel Strainer Backwash Piping Floor Penetration	2.4.2.3-1	3.3.1.16 (Auxiliary system link)
All Components	2.4.2.5-1	Various Auxiliary system links

3.5.1-1 In discussing below-grade concrete at FCS in LRA Table 3.5-1, row 3.5.1.07, you have determined that the below-grade environment is relatively benign, which exempts you from having an aging management program for below-grade inaccessible concrete components. However, since the containment tendon gallery is below grade and is accessible for inspection, its condition could provide confirmation as to the benign characteristics of the soil/ground-water environment. Therefore, please provide information regarding the condition of the containment tendon gallery which supports your assessment regarding the benign characteristics of the below-grade media.

3.5.1-2 The LRA Table 2.4.1-1 entry entitled “Containment Grout in Ambient Air” identifies several sections of the LRA Section 3 AMR results that are credited with managing the aging of grout. The staff is unclear with regard to the location of grout within containment. In order to determine whether the credited programs are adequate to manage aging of grout, please clarify the location of grout within the containment and provide information to demonstrate that the containment grout will be adequately managed during the period of extended operation.

3.5.1-3 In discussing the biological shield temperatures in LRA Table 3.5-1, row 3.5.1.10, you state: “Technical Specification Limiting Condition of Operation 2.13 requires that the annulus exit temperature from the nuclear detector cooling system shall not exceed a temperature found to correlate to 150 °F concrete temperature.” The staff is unclear regarding how the correlation between the annulus exit temperature and the concrete temperature is developed. The staff needs to understand the correlation to have reasonable assurance that the aging effects associated with the concrete elements will be adequately managed during the period of extended operation. Please provide more information regarding the exit temperature, and how the exit temperature from the cooling system controls the temperature of biological shield concrete. What are the operating measured temperatures in the annulus between the reactor vessel and the biological shield wall concrete?"

3.5.1-4 In the last sentence of the "Discussion" column in LRA Table 3.5-1, row 3.5.1.10, the applicant concludes, "Therefore, no portions of concrete containment exceed specified temperature limits and no aging management is required." The staff notes that the 150 °F threshold limit provided in CC-3400 of ASME Section III, Division 2, and in Appendix A of ACI-349, "Code Requirements for Nuclear Safety Related Concrete Structures," ensure that the concrete properties will not be significantly affected up to that temperature. However, use of this guidance will not guard against aging degradation of concrete (i.e., cracking, spalling, and resulting reinforcing bar corrosion). The staff believes that these concrete aging effects must be managed to ensure that the intended functions of the associated structures is maintained during the period of extended operation. GALL program XI.S6, "Structural Monitoring Program," recommends the use of ACI 349.3R-96 for managing the aging of concrete structural components inside the containment. The ACI report recommends the inspection of these structures every five years. Please provide a brief description of the current program(s) used to monitor the condition of the concrete components inside the containment, together with the significant findings of the past inspections. The components of interest are the biological shield walls, the support areas of the reactor vessel, steam generators, and reactor coolant pumps. Include a justification for why the current program(s) is not needed to manage aging of concrete components during the period of extended operation, or add the program(s) to those credited for managing aging during the period of extended operation.

3.5.1-5 Row entry 3.5.1.23 in LRA Table 3.5-1 addresses cracking due to SCC for stainless steel liners exposed to water.

a. Please clarify why this row entry (3.5.1.23) is referenced for several concrete components in LRA Section 2.4, "Scoping and Screening Results: Structures."

b. Also, in row entry 3.5.1.23, the applicant states: "The combinations of components, materials and environments identified in NUREG-1801 are not applicable to FCS." The GALL report identifies concrete tanks as Group 7 structures, and steel tanks as Group 8 structures. It is unclear to the staff whether the applicant is stating that neither group contains liners. The staff believes that, if the subject structures contain liners, these liners may be needed to ensure the structural integrity of the tanks. On this basis, please clarify whether any Group 7 or Group 8 structures that are within the scope of license renewal and subject to an AMR, contain liners. If so, please provide the basis for why these liners are not needed to maintain the intended function of the subject containers. Specifically, please provide a list of safety-related tanks that are in the FCS yard, in buildings, and those below grade. Please provide materials and environments they are subjected to, and the aging management program(s) applicable to these tanks.

3.5.1-6 LRA Table 3.5-1, row 3.5.1.16, states that the structures monitoring program is credited for managing various types of aging effects for the subject components.

However, in the discussion column, the applicant states that aging management is not required because the concrete at FCS was designed in accordance with ACI 318-63. The statement in the discussion column contradicts the information regarding the structures monitoring program. Please resolve the discrepancy.

3.5.1-7 In the discussion column of LRA Table 3.5-1, row 3.5.1.16, the applicant refers to concrete Classes A, B, and C at FCS. The staff is not familiar with these concrete classes. In order to confirm whether aging management is not required for these concrete classes, please provide the definition for each class of concrete, the differences among them, and their applicability.

3.5.1-8 In the discussion column of LRA Table 3.5-1, rows 3.5.1.16 and 3.5.1.17, the applicant states that periodic monitoring of below-grade groundwater chemistry will be conducted during the period of extended operation. What program(s) will be used to perform this periodic monitoring and specify the frequency at which the monitoring of groundwater chemistry will be performed?

3.5.1-9 LRA Table 3.5-1, row 3.5.1.02, states that the bellows at FCS are not exposed to a corrosive environment; therefore, stress corrosion cracking is not an aging effect requiring management. Stress corrosion cracking is a concern for bellow assemblies with dissimilar metal welds. This aging effect can occur without an accompanying corrosive environment. Also, examination Categories E-B & E-F, and augmented VT-1 visual examination are used to detect stress corrosion cracking in dissimilar welds. On this basis please provide the basis for not considering the use of Examination Categories E-B & E-F, and augmented VT-1 visual examination of FCS bellows and dissimilar welds for the period of extended operation.

3.5.1-10 With respect to Items 2.b, 2.c and 2.d of row 3.5.1.12 of LRA Table 3.5-1, the discussion provides generic reasons for why the corrosion of inaccessible areas would not be significant under normal circumstances. However, the staff is concerned that there could be some plant-specific or unexpected situations under which the corrosion could be significant. In order for the staff to have reasonable assurance that corrosion in inaccessible areas is insignificant at FCS, and since the applicant appears to have been doing past monitoring/maintenance work, please provide information on FCS operating experience with regard to corrosion associated with the inaccessible areas for FCS' containment liner plates (e.g., liner corrosion at the moisture barrier, corrosion of basemat portion of liner underneath partially cracked containment floor concrete due to borated water spills, etc.), and demonstrate that the AMPs currently in place are adequate for managing the FCS containment liner aging effects for the period of extended operation.

3.5.1-11 With respect to LRA Table 3.5-2, row 3.5.2.25, FCS appears to have containment stainless steel threaded fasteners (the applicant identifies containment stainless steel threaded fasteners in LRA Table 2.4.1-1) which are not addressed in GALL. The applicant has decided that no AMP is needed for stainless steel fasteners in ambient air, whereas the staff is concerned that in a wetted or highly moisturized air environment, an AMP may be needed for the stainless steel fasteners. On this basis, please confirm that, for FCS, there are no containment stainless steel threaded fasteners used in a wetted or highly moist air environment. Otherwise, justify why an aging management program is not needed to manage loss of material for fasteners in a wetted or moist environment.

3.5.1-12 Considering the vulnerability of concrete structural components, the staff has required previous license renewal applicants to implement an aging management program to manage the aging of these components. The staff position is that cracking, loss of material, and change in material properties are plausible and applicable aging effects for concrete components inside containment as well as for other structures outside containment. For inaccessible concrete components, the staff does not require aging management if the applicant is able to show that the soil/water environment is nonaggressive; however, for all other concrete components, inspection through an aging management program is required.

For many of the concrete components listed in LRA Section 2.4, “Scoping and Screening Results: Structures,” the staff was unable to verify that the aging effect(s) identified for these components in LRA Table 3.5-1 will be managed by an appropriate aging management program. Provide clarification regarding the AMR conclusions for

- containment concrete above grade,
- containment concrete below grade,
- interior containment concrete in ambient air,
- containment grout in ambient air,
- auxiliary building concrete below grade,
- auxiliary building exterior concrete in ambient air,
- auxiliary building interior concrete in ambient air,
- diesel fuel oil tank foundation,
- diesel generator missile shield enclosure concrete below grade,
- diesel generator missile shield enclose concrete in ambient air,
- turbine and service building concrete above grade,
- turbine and service building concrete below grade,
- turbine and service building concrete in ambient air,
- turbine and service building grout in ambient air,
- intake structure - concrete below grade,
- intake structure - concrete exposed to raw water,
- intake structure - concrete exterior in ambient air,
- intake structure - concrete interior,
- duct banks - exterior concrete in ambient air,
- duct banks - concrete below grade,
- duct banks - interior concrete.

For each concrete component identified above, identify the applicable aging effects and the program that will be used to manage each aging effect.

3.5.1-13 Considering the vulnerability of carbon steel structural components, the staff position is that loss of material is a plausible and applicable aging effect for carbon steel components inside containment as well as for other structures outside containment. For carbon steel in an indoor/air-conditioned environment, the staff does not require aging management. In addition, for steel imbedded in concrete in inaccessible areas, the staff does not require aging management if the applicant is able to show that the soil/water environment is nonaggressive.

For many of the carbon steel structural components listed in LRA Section 2.4, “Scoping and Screening Results: Structures,” the staff was unable to verify that the aging effect(s) identified for these components in LRA Table 3.5-1 will be managed by an appropriate aging management program. Provide clarification regarding the AMR conclusions for carbon steel components in LRA Section 2.4 that reference row entry 3.5.1.16 in LRA Table 3.5-1.

3.5.1-14 For interior containment concrete in ambient air and containment grout, LRA Table 3.5-1 row entries 3.5.1.15 and 3.5.1.16 are referenced. The ‘Discussion’ columns for these two row entries appear to contradict each other regarding the applicability of reaction with aggregates as an applicable aging mechanism, which leads to the aging effect cracking. Please clarify whether reaction with aggregates, and hence cracking, is considered to be applicable for interior containment concrete in ambient air and containment grout.

3.5.1-15 The ‘Discussion’ column for row entry 3.5.1.07 in LRA Table 3.5-1 appears to indicate that the identified aging effects (change in material properties, cracking, loss of material) for concrete elements (foundation, walls, dome) are not applicable at FCS for below-grade concrete components. This same row entry (3.5.1.07) is also referenced for a number of above-grade concrete components listed in LRA Section 2.4, “Scoping and Screening Results: Structures.” Clarify whether the aging effects (change in material properties, cracking, loss of material) for this row entry will or will not be managed for above-grade concrete components.

3.5.1-16 The ‘Discussion’ column for row entry 3.5.1.16 in LRA Table 3.5-1 of the LRA indicates that freeze-thaw, which leads to the aging effect cracking, is not an applicable aging mechanism for concrete components at FCS. However, row entry 3.5.1.15 in LRA Table 3.5-1 appears to indicate that cracking resulting from freeze-thaw or reaction with aggregate is an applicable aging effect. Please clarify this discrepancy.

3.5.1-17 For concrete exposed to raw water in the intake structure, LRA Table 2.4.2.3-1 identifies AMR row entries 3.5.1.16 and 3.5.2.32 in LRA Tables 3.5-1 and 3.5-2, respectively. The latter row entry (3.5.2.32) is for component support stainless steel threaded fasteners exposed to ambient air and identifies cracking as the aging effect. Provide clarification regarding the reference to row entry 3.5.2.32 for concrete exposed to raw water in the intake structure.

3.5.1-18 In LRA Table 2.4.2.6-1 for component supports, AMR result 3.5.1.28 in LRA Table 3.5-1 is referenced for the lubrite plate in ambient air. Provide clarification regarding the applicability of this row entry for the lubrite plate in ambient air. Specifically, identify the applicable aging effects for lubrite in ambient air and the programs credited with managing the aging effects.

3.5.1-19 The discussion column of row numbers 3.5.1.16 and 3.5.1.17 of LRA Table 3.5-1 state that the below-grade exterior reinforced concrete at FCS is not exposed to an aggressive environment. To confirm that the below-grade environment is not aggressive, provide water chemistry data, such as pH, chlorides, and sulfates. In order for the staff to assess the variability of the below-grade environment, please provide the above data since initial plant construction.

3.5.3-1 Based on the information in LRA Table 3.5-3, row number 3.5.3.04, and in FCS AMP B.2.10, "Structures Monitoring Program," the applicant plans to inspect and review the masonry walls in accordance with enhanced GALL program XI.S5, "Masonry Wall Program." As the ungrouted masonry walls in containments are subjected to higher sustained temperatures (> 110 °F), humidity, and radiation, please provide the following information for the staff to make a reasonable conclusion regarding the adequacy of these walls during the period of extended operation:

- location of these walls,
- environment (temperature, humidity, radiation) to which they are subjected,
- time-interval for examining these walls, and
- operating experience related to these walls.

3.6 <u>Electrical and Instrumentation and Controls</u>

3.6-1 For inaccessible medium-voltage (2 kV to 15 kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements, LRA Table 3.6-1, row 3.6.1.04, states that modifications were made to the duct banks to preclude moisture intrusion; therefore, there is no aging effect requiring management. However, it is not clear to the staff what actions will be taken to assure that the modifications made to prevent inaccessible non-EQ medium-voltage cables from being exposed to significant moisture will be maintained intact during the period of extended operation. Therefore, for these non-EQ cables that are within the scope of license renewal, provide a description of the program that will assure that the modifications are maintained intact to prevent intrusion of water into the duct banks. In addition, provide a description of the AMP that will be relied upon for accessible and inaccessible medium-voltage cables installed in conduits, cable trenches, cable troughs, underground vaults, or direct buried installations.

4.1 <u>Identification of Time-Limited Aging Analyses</u>

4.1-1 LRA Table 4.1-1 identifies time-limited aging analyses (TLAAs) applicable to FCS. Tables 4.1-2 and 4.1-3 in NUREG-1800 identify potential TLAAs determined from the review of other license renewal applications. The LRA indicates that NUREG-1800 was used as a source to identify potential TLAAs. For those TLAAs listed in Tables 4.1-2 and 4.1-3 of NUREG-1800, that are applicable to PWR facilities and not included in Table 4.1-1 of the LRA, discuss whether there are any calculations or analyses that address these topics at FCS. If calculations or analyses exist that address these topics, discuss how the these calculations or analyses were evaluated against the TLAA definition provided in 10 CFR 50.3.

4.2 Reactor Vessel Neutron Embrittlement

4.2-1 Title 10 CFR 54.21(c)(1) states that the applicant shall demonstrate that:

(i) the analyses remain valid for the period of extended operation;
(ii) the analyses have been projected to the end of the period of extended operation; or
(iii) the effects of aging on the intended function will be adequately managed for the period of extended operation

The applicant indicates that the technical specifications will continue to be updated as required by either Appendices G or H of 10 CFR Part 50, or as operational needs dictate. This will assure that operational pressure-temperature and LTOP limits remain valid for current and projected cumulative neutron fluence levels. However, the analyses have not been projected to the end of the period of extended operation.

To comply with 10 CFR 54.21(c)(1) the applicant must provide the analyses that have been projected to the end of the period of extended operation or indicate that the reactor pressure vessel can be operated through the end of the period of extended operation with the projected pressure-temperature and LTOP limits.

4.2-2 LRA Section 4.2.4 indicates that preliminary calculations have shown that the vessel beltline Charpy upper-shelf energy (USE) for the limiting weld will be approximately 54.5 ft-lb based on position 1.2 of RG 1.99. The applicant indicates that this analysis will be finalized and formally revised to reflect that it bounds the minimum approved fluence value at the end of plant life. In order for the staff to complete its review of this TLAA issue, the applicant must submit the results of its analysis based on the projected neutron fluence at the end of the period of extended operation. Therefore, the applicant is to provide the following information:

a) The projected peak neutron fluence at a depth of 1/4 T (thickness) for each beltline material at the end of the period of extended operation

b) The method (either position 1.2 or position 2.2 of RG 1.99, Revision 2) for determining the decrease in Charpy USE for each beltline material

c) The unirradiated Charpy USE for each beltline material

d) The amount of copper for each beltline material and references for all surveillance data

e) Based on the information in items a) through d), the projected Charpy USE for each beltline material at the end of the period of extended operation

f) The impact of surveillance data on the projected Charpy USE

4.3 Metal Fatigue

4.3.1-1 LRA Section 4.3.1 contains a discussion of the transients used in the design of the reactor coolant system components at FCS. The LRA indicates that none of the operational cycles are expected to exceed the number used for the design of these components, for those cycles counted. Provide the following information for each of the transients described in LRA Section 4.3.1:

1. The current number of operating cycles and a description of the method used to determine the number of the design transients from the plant operating history.

2. The number of operating cycles estimated for 60 years of plant operation and a description of the method used to estimate the number of cycles at 60 years.

3. A comparison of the design transients listed in the LRA with the transients monitored by the Fatigue Monitoring Program (FMP) described in LRA Section B.2.4. Identify any transients listed in the LRA that are not monitored by the FMP and explain why it is not necessary to monitor these transients.

4.3.2-1 LRA Section 4.3.2 discusses OPPD's evaluation of the impact of the reactor water environment on the fatigue life of components. The discussion references the fatigue-sensitive component locations for an older vintage Combustion Engineering plant identified in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." The LRA indicates that the later environmental fatigue correlations contained in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue on Fatigue Design Curves of Austenitic Stainless Steels," were considered in the evaluation. Provide the results of the usage factor evaluation for each of the six component locations listed in NUREG/CR-6260.

4.3.2-2 LRA Section A.2.10 provides the FMP discussion for the USAR supplement. The discussion indicates that the automated cycle counting software FatiguePro will be used to monitor thermal fatigue of the components in the program. The discussion also indicates that an FCS site-specific evaluation is being performed to address environmental fatigue and that appropriate program enhancements will be made prior to the period of extended operation. However, LRA Section 4.3.2 indicates that the environmental fatigue evaluations are complete. This appears to be a discrepancy. Describe the planned FMP enhancements that will be implemented based on the results of the environmental fatigue evaluations.

4.3.2-3 LRA Section 4.3.2 contains a discussion of the proposed aging management program to address fatigue of the FCS pressurizer surge line. The discussion indicates the aging management program will consist of an inspection program. The LRA also indicates that the results of the surge line inspections will be used to assess the appropriate approach for addressing environmentally-assisted fatigue of the surge lines. However, LRA Section 4.3.3 indicates that a reevaluation of the fatigue usage of critical areas of the surge line will be performed prior to the period of extended operation and that the bounding locations will be included in the FMP. It is not clear to the staff how environmental effects will be factored into the proposed surge line evaluation. Describe how the effect of the reactor water environment will be considered in the reevaluation of the critical areas of the surge line and how the results of this evaluation will be monitored by the FMP.

4.3.4-1 LRA Section 4.3.4 contains a discussion of the analysis of Class II and III components at FCS. The LRA indicates that the USAS B31.1 limit of 7000 equivalent full range cycles may be exceeded during the period of extended operation for the NSSS sampling system and that the affected portions of the NSSS sampling system would be tracked by the FMP. Provide the calculated thermal stress range for these affected portions of the NSSS sampling system.

4.5 Concrete Containment Tendon Pre-Stress

4.5-1 For acceptance criterion for tendon prestressing force, the LRA states: "If at any time surveillance testing indicates a decrease in the tendon force below the given limit line, corrective action will be taken in accordance with the Technical Specifications." This is one of the criterion in IWL-3221. Additionally, 10 CFR 50.55a(b)(2)(viii)(B) requires: "When evaluation of consecutive surveillances of prestressing forces for the same tendon or tendons in a group indicates a trend of prestressing loss such that the tendon forces will be less than the minimum design prestress requirements before the next inspection interval, an evaluation must be performed and reported in the Engineering Evaluation Report as prescribed in IWL-3300." Based on these requirements, the staff requests the applicant to clarify whether the acceptance criterion in the LRA complies with the requirements of IWL-3221 and 10 CFR 50.55a(b)(2)(viii)(B).

4.5-2 Title 10 CFR 50.55a(b)(2)(viii)(B) requires the development of a trend line of measured prestressing forces so that the licensee can decide whether the prestressing tendon forces during the next inspection interval will remain above the "Lower Limit - Dome," and "Lower-Limit-Wall," as plotted in USAR Figure 5.10-3. The applicant addresses this TLAA using 10 CFR 54.21(c)(1)(iii) and Section X.S1 of the GALL report, as part of its operating experience. In order to confirm that the prestressing tendon forces will remain above the lower limits for the dome and wall during the period of extended operation, the staff requests that the applicant provide information related to the trend lines for wall and dome tendons compared to the established lower limits. Guidance for statistical considerations in developing the trend lines is given in Attachment 3 of IN 99-10, Revision 1, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments."

4.6 Containment Liner Plate and Penetration Sleeve Fatigue

4.6-1 LRA Section 4.6 discusses the fatigue analysis of the containment liner and penetration sleeves. The LRA indicates that the observed buckling of the liner plate is larger than was assumed in the original analysis. The LRA indicates that this condition has been evaluated and found acceptable for the current term. The LRA further indicates that OPPD will complete an analysis for the 60-year period prior to the period of extended operation. Describe the analysis that was performed to show the containment liner plate/penetration sleeve meets acceptance criteria for the current term. Provide the calculated usage factor obtained from this analysis.

4.7.1 Reactor Coolant Pump Flywheel Fatigue

4.7.1-1 Two crack growth analyses are referenced in LRA Sections 4.7.1.1 and 4.7.1.2. One is described as Reference 4.7-1 and the other is described as an analysis performed by ABB. Title 10 CFR 54.21(c)(i) and (ii) discuss analyses required as part of the TLAA. In order to confirm that the applicant has satisfied the regulatory requirements, the staff needs to review these analyses. Please provide the analyses and provide any references that indicate that they have been previously reviewed by the NRC.

4.7.2 Leak-Before-Break (LBB)

4.7.2-1 As a result of the V.C. Summer event in which primary water stress corrosion cracking (PWSCC) was identified in an Inconel 82/182 main coolant loop-to-reactor pressure vessel weld, the NRC staff has become concerned about the impact of PWSCC on licensee LBB evaluations. NUREG-1061, Volume 3, "Report of the U.S. Nuclear Regulatory Commission Piping Review Committee, Evaluation of Potential for Pipe Breaks," which addresses the general methodology accepted by the NRC staff for demonstrating LBB behavior, stipulates that no active degradation mechanism may be present in a line which is under consideration for LBB. Draft Standard Review Plan 3.6.3. "Leak-Before-Break Evaluation Procedures,"suggests that lines with potentially active degradation mechanisms may be considered for LBB approval provided that two mitigating actions/programs are in place to address the potential active degradation mechanism.

The NRC considers the resolution of the impact of PWSCC on existing LBB evaluations to be a 10 CFR Part 50, operating reactor issue. The NRC staff has previously addressed this issue with the industry's PWR Materials Reliability Project (MRP) and received an interim report from the MRP, "PWR Materials Reliability Project, Interim Alloy 600 Safety Assessment for U.S. PWR Plants (MRP-44), Part 1: Alloy 82/182 Pipe Butt Welds," dated April 2001, which attempted to provide a technical basis for addressing this issue. The NRC expects to receive a final version of the MRP-44, Part 1 report from the MRP. Based on the information in the final MRP report and any additional, relevant information available to the NRC staff, the NRC will evaluate what actions or analyses, if any, may be required to confirm the continued applicability of existing licensee LBB evaluations.

Regarding the FCS LRA, the NRC staff requests that Omaha Public Power District (OPPD) provide an applicant commitment which states that for the period of extended operation of FCS, OPPD will implement actions or perform analyses, as deemed to be necessary by the NRC, to confirm continued applicability of existing FCS LBB evaluations. These actions or analyses will be consistent with those required to address the impact of PWSCC on existing LBB evaluations under 10 CFR Part 50 considerations."

B.1 Aging Management Programs

B.1-1 Several FCS AMPs are described by the applicant as being consistent with GALL, but with some deviation from GALL. These deviations are of three types: (1)

exceptions to GALL, (2) clarifications to GALL, or (3) enhancements to GALL. The staff cannot find definitions for these terms. In order to assess the adequacy of these deviations from GALL, and to determine the impact of the deviations on the ability of the AMP to effectively manage the aging effects for which the AMP is credited, the staff requests the applicant to provide the definitions for the terms "exception to GALL"; "clarification to GALL"; and "enhancement to GALL."

B.1-2 If any of the applicant's RAI responses require revisions to the associated program and activity descriptions provided in the USAR Supplement (LRA Appendix A), the staff requests the applicant to provide a list of the revised USAR Supplement program and activity descriptions along with the revised program and activity descriptions.

B.1.1 Bolting Integrity Program

B.1.1-1 According to the applicant's statement in LRA Section B.1.1, the bolting integrity program is consistent with NUREG-1801, with the exception that FCS has not identified stress corrosion cracking as a creditable aging effect requiring management for high-strength carbon steel bolting in plant indoor air. It is the staff's understanding that this exception means that this program will follow all the requirements in NUREG-1801 with the exception of high-strength carbon steel bolting for steel structures, pipe supports, HVAC supports, electrical supports, and equipment supports. Is the staff's understanding of the program correct?

B.1.2 Water Chemistry

B.1.2-1 LRA Section B.1.2 states that the applicant's chemistry program is consistent with chemistry-related portions of the GALL program for the closed-cycle cooling water systems. Because the applicant has combined aspects of several GALL programs into its chemistry program, and in order to adequately review the scope of the applicant's chemistry Program, the staff needs to know to what extent the program relies on the GALL's closed-cycle and open-cycle cooling water programs. The applicant should clarify how the features of the GALL closed-cycle and open-cycle cooling water programs are incorporated into the FCS chemistry and cooling water corrosion programs.

B.1.3 Containment ISI

B.1.3-1 In order to determine whether the applicant's program effectively manages aging in the liner plate, the staff requests the applicant to provide a summary of the significant degradations (i.e. metal thinning in excess of 10 percent of the nominal thickness of the metal) discovered during the last inspection of the liner in accordance with the program, and a summary of corrective actions taken.

B.1.3-2 NRC inspections during the 1990's noted a large amount of grease leakage from the tendons at FCS, specifically, in the ring-girder areas of the containment. On the basis of this plant experience, the staff requests to applicant to provide an assessment of such leakages on tendon performance (i.e., absence of corrosion protection and potential degradation of tendon wires) during the period of extended operation, and of the effectiveness of the actions taken to alleviate the future grease leakages.

B.1.4 Containment Leak Rate Program

B.1.4-1 The applicant is requested to provide a summary of significant deviations from the acceptance criteria (e.g., twice the technical specification acceptance criteria) for Type A, Type B, and Type C testing. This operating experience information is needed for the staff to assess the current leaktight characteristics of the FCS containment, and assess its behavior during the period of extended operation.

B.1.5 Flow Accelerated Corrosion Program

B.1.5-1 In LRA Section B.1.5, the referenced EPRI document, NSAC-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program," recommends use of a predictive method for determining the rate at which component degradation by FAC is occurring. This information was not provided in the LRA. What methods are used at FCS for predicting component degradation by FAC?"

B.1.7 Reactor Vessel Integrity Program

B.1.7-1 In a license amendment dated August 3, 2000, and letters dated November 17, 2000, and February 14, 2001, the licensee provided RT_{PTS} analyses for the materials in the FCS reactor vessel. The August 3, 2000, letter contains report CEN-636, "Evaluation of Reactor Vessel Surveillance Data Pertinent to the Fort Calhoun Reactor Vessel Beltline Materials." Table 10 in CEN-636, Revision 2, provides the chemistry factor and the predicted RT_{PTS} value through 2033 for each plate and weld in the FCS reactor vessel beltline. Many of the materials RT_{PTS} values are dependent upon surveillance data which could effect their RT_{PTS} value. In addition, one weld is projected to be only 2 ^{o}F below the PTS screening limit and one weld is projected to be 15 ^{o}F below the PTS screening limit at the end of the period of extended operation. To determine whether the reactor vessel integrity program will adequately monitor neutron irradiation embrittlement, provide the following information:

a. confirm that the RT_{PTS} value identified in Table 10 of CEN-636 is applicable through the end of the period of extended operation for FCS.

b. For each material in Table 10 of CEN-636 identify the projected neutron fluence at the end of the period of extended operation and the neutron flux assumed for future core loadings.

c. For each chemistry factor in Table 10 of CEN 636 that was calculated using surveillance material, identify the source of the surveillance material.

d. Explain how the reactor vessel integrity program will monitor future core loadings to ensure that no beltline materials will exceed the PTS screening limit in 10 CFR 50.61 .

e. Identify how the reactor vessel integrity program will monitor future surveillance capsule data from FCS and other facilities to ensure that no beltline materials will exceed the PTS screening limit in 10 CFR 50.61 or the Charpy upper-shelf energy screening criteria in Appendix G, 10 CFR Part 50.

B.2.1 Boric Acid Corrosion Prevention Program

B.2.1-1 In LRA Section B.2.1, the applicant described several enhancements which it proposes to introduce to the GALL boric acid corrosion program. Since these enhancements will modify the program, the staff needs to understand to what extent the modification of the program will affect its ability to manage the AERMs caused by leaking boric acid. Therefore, the applicant should provide a description of the expected impacts caused by the enhancement to the program.

B.2.1-2 As a result of the insights gained from the recent discovery of boric acid-induced corrosion of the Davis-Besse vessel, the staff requests that the applicant address the changes that were made to its boric acid corrosion prevention program in response to the Davis-Besse event.

B.2.3 Diesel Fuel Monitoring and Storage

B.2.3-1 Leak detection is being employed to monitor the condition of the tank in lieu of ultrasonic testing. The staff believes that ultrasonic testing allows for the detection of aging effects in sufficient time to take corrective action to maintain the component's intended function. Detection of a leak indicates that significant fuel oil tank degradation has already occurred. On this basis, the staff believes that leak detection is an insufficient means to detect tank degradation. Therefore, (1) provide an aging management program that will adequately detect tank degradation in sufficient time to allow for corrective action before loss of the tank's intended function, or justify how leakage detection will accomplish this goal, (2) discuss the corrective actions that would be taken if leakage is detected, (3) clarify whether inspections will be performed in the other storage tanks which credit this program for aging management, and (4) if there is no inspection of the tank bottom, describe the aging management of other low points of the system where impurities can accumulate.

B.2.3-2 The applicant proposes to inspect the diesel fuel oil day tanks and to perform a fuel analysis of the fire protection day tank. In order to evaluate whether these activities will adequately manage aging in the subject components, please discuss the nature of the fuel analysis and day tank inspection, including the constituents to be analyzed, the frequency of the analyses and inspections, the acceptance criteria, and the corrective actions if degradation is found.

B.2.3-3 It is stated under "Parameters Monitored/Inspected," that particulate analysis of fuel oil is performed but is not credited for aging management. The staff requests the applicant to confirm whether the diesel fuel oil quality is monitored for water and sediment contamination in accordance with ASTM Standards D1796 and D2709, as stated in XI.M30 of the GALL Report.

B.2.4 Fatigue Monitoring Program

B.2.4-1 LRA Section B.2.4 describes the FCS FMP. The first paragraph in Section B.2.4 indicates that the scope of the FMP includes those plant specific components identified in LRA Table 3.1-2 of the application for which the FMP is identified as an aging management program. However, LRA Table 3.1-2 only lists the FMP as an aging management program for the reactor vessel internals-flow skirt. Clarify the scope of the components covered by the FMP.

B.2.4-2 LRA Section B.2.4 discusses the operating experience at FCS that led to enhancements to the FMP. The LRA indicates that an assessment of the operation of the chemical and volume control system (CVCS) was performed to ensure that the appropriate transients were monitored by the FMP. Describe the enhancements to the FMP that resulted from this assessment.

B.2.5 Fire Protection

B.2.5-1 LRA Section B.2.5 states that the fire protection program is consistent with XI.M26, “Fire Protection,” and XI.M27, “Fire Water System,” as identified in the GALL report, with certain enhancements to several program elements. In order for the staff to evaluate the adequacy of the applicant’s fire protection program and reach a conclusion that it is consistent with the guidance in the GALL report, the staff requests that the applicant confirm the following:

1. The additional guidance which will be added to the diesel fire pump maintenance procedure during enhancements will ensure that the diesel-driven fire pump is under observation during performance tests such as flow and discharge tests, sequential starting capability tests, and controller function tests for detecting any degradation of the fuel supply line.

2. The guidance which will be added to halon and fire damper inspection procedures will include periodic visual inspection and function tests at least once every six months to examine signs of degradation of the halon/carbon dioxide fire suppression system. The suppression agent charge pressure will be monitored in the test. Material conditions that may affect the performance of the system, such as corrosion, mechanical damage, or damaged dampers are observed during these tests. Inspection will be performed at least once every month to verify that the extinguishing agent supply valves are open, and the system is in automatic mode.

3. The specific guidance which will be added related to the fire door inspections will ensure that hollow metal fire doors are visually inspected at least once bimonthly for holes in the skin of the door. Fire door clearances are also checked at least once bimonthly as part of an inspection program. Function tests of fire doors are performed daily, weekly, or monthly (which may be plant-specific) to verify the operability of automatic hold-open, release, closing mechanisms, and latches.

B.2.5-2 The staff has proposed a revision to the fire protection system aging management program inspection criteria in the GALL report for wall thinning of piping due to corrosion. The revised staff position states that each time the system is opened, oxygen is introduced into the system, and this accelerates the potential for general corrosion. Therefore, the staff has recommended that a non-intrusive means of measuring wall thickness, such as ultrasonic inspection, be used to detect this aging effect. The staff recommends that, in addition to a baseline ultrasonic inspection of the fire protection piping that is performed before exceeding the current licensing term, the applicant should perform ultrasonic inspections at 10-year intervals thereafter.

Verify whether the inspection criteria for the applicant's fire protection program conforms with the staff position, as outlined above.

B.2.5-3 The program description for GALL program XI.M27, "Fire Water System," states that underground piping (among other components) is to be managed by the program. However, the program does not address aging management of underground piping. In order to evaluate whether the applicant's fire protection program will adequately manage aging of underground piping in the fire water system, please describe the environmental and material conditions that exist on the interior surface of below-grade fire protection piping, and demonstrate how the above-ground piping conditions can be extrapolated to determine the below-ground piping conditions, and how the fire protection program will manage aging of underground piping. If a meaningful extrapolation cannot be made, demonstrate how underground piping will be adequately managed during the period of extended operation to assure maintenace of the component intended function.

B.2.5-4 The staff is concerned that the applicant's fire protection program may not adequately manage aging of coatings in steel structures, since neither XI.M26 nor XI.M27 address coatings. On this basis, the staff requests the applicant to identify any steel structures within the scope of license renewal and subject to an AMR which depend on coatings to protect the steel structures from age-related degradation. For any such coatings, describe the aging management activities that manage the aging effects for the coatings and identify what aging management program performs these activities.

B.2.5-5 LRA Section B.2.5 states that the applicant's AMP is consistent with GALL AMPs XI.M26, "Fire Protection," and XI.M27, "Fire Water System." The staff has finalized interim staff guidance (ISG) to revise the fire protection system AMPs in the GALL report. The relevant portions of the ISG are summarized below.

1. <u>Staff Position for Wall Thinning of Fire Protection Piping Due to Internal Corrosion</u>

   Fire Protection piping is typically designed for a 50-year life in industrial applications. The limiting aging mechanism is general corrosion. Because the general corrosion of FP piping is typically very uniform, loss of intended function as a result of catastrophic failure caused by wall thinning throughout the system is possible and needs to be managed. However, internal inspections (performed during each refueling cycle by disassembling portions of the FP piping), as stated in NUREG-1801, Chapter XI.M27, "Fire Water Systems," are not the best means to detect this aging effect. Each time the system is opened, oxygen is introduced into the system and accelerates the potential for general corrosion. Therefore, the staff recommends that a non-intrusive means of evaluating wall thickness, such as volumetric inspection or plant maintenance inspection, be used to detect this aging effect.

The staff initially considered that a one-time ultrasonic inspection performed near the end of the operating term would be sufficient to detect wall thinning. However, further evaluation determined that it may be difficult to justify a one-time ultrasonic inspection, in light of the possibility of changes in operating conditions that may require the applicant to open the FP systems more frequently (e.g., for the 50-year service life sprinkler head testing) and allow oxygen in. Therefore, the staff is recommending that, in addition to a baseline wall thickness evaluation of the fire protection piping before exceeding the current license term, the applicant should perform pipe wall thickness evaluations at plant-specific intervals during the period of extended operation. The plant-specific inspection intervals are to be determined by engineering evaluation of the FP piping to detect degradation prior to the loss of intended function.

As an alternative to pipe wall thickness evaluations, an applicant may use its plant maintenance process to include a visual inspection of the internal surface of the FP piping upon each entry to the system for routine or corrective maintenance, as long as the applicant can demonstrate that it will perform inspections (based on past maintenance history) on a representative number of locations on a periodic basis. As part of these inspections, applicants need to be sensitive to wall thickness to ensure against catastrophic failure, and to the inner diameter of the piping, as it applies to the flow requirements of the FP system.

As part of the review of this issue and the above stated approach, a concern was raised as to the inspection specifications of the internal surface of below-grade FP piping. The staff acknowledges that some applicants may be able to demonstrate that the environmental and material conditions that exist on the interior surface of below grade FP piping are similar to the conditions that exist within the interior surface of the above grade FP piping. If an applicant makes such a demonstration, the staff agrees that the results of the interior inspections of the above-grade FP piping can be extrapolated to evaluate the interior condition of the below grade FP piping. If not, additional inspection activities are needed to provide reasonable assurance that the intended function of below grade FP piping will be maintained consistent with an applicant's current licensing basis for the period of extended operation.

2. <u>Staff Position for Testing of Sprinkler Heads</u>

National Fire Protection Association (NFPA) 25, 1999 Edition, Section 2.3.3.1, "Sprinklers," states, "where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing." NFPA 25 also contains guidance to perform this sampling every 10 years after the initial field service testing.

The 50-year service life of sprinkler heads does not necessarily equal the 50th year of operation in terms of licensing. The service life is defined from the time the sprinkler system is installed and functional. In most cases, sprinkler systems are in place several years before the operating license is issued. However, sprinkler systems in some plants may have been installed after the plant was placed in operation. The staff interpretation, in accordance with NFPA 25, is that sprinkler head testing should be performed at year 50 of sprinkler system service life, not at year 50 of plant operation, with subsequent sprinkler head testing every 10 years thereafter.

On the basis of this ISG, the staff requests the applicant to discuss how it plans to follow the guidance in the ISG, and how this will be reflected in AMP B.2.5.

B.2.7 Periodic Surveillance and Preventive Maintenance (PM) Program

B.2.7-1 The staff has read the program description for this aging management program, and is concerned that it's purpose may overlap the surveillance and maintenance activities associated with 10 CFR 50.65 "Requirements for monitoring the effectiveness of maintenance at nuclear power plant," (the Maintenance Rule). In order to better understand how this aging management program will differ from, and supplement, the Maintenance Rule, please discuss the surveillance and preventive maintenance activities that will be performed by this program, and how they will supplement activities performed under the Maintenance Rule, including the criteria to be used and the frequency to evaluate the effectiveness of the program in achieving its goals of aging management.

B.2.7-2 Item 3, "Parameters Monitored or Inspected," of LRA Section B.2.7 considers surface condition as one of the parameters for monitoring age-related degradations. The staff believes that to adequately determine surface degradation of concrete, physical properties such as honeycombs, chemical leaching and/or discoloration should be inspected. Does the scope of this inspection program cover monitoring of changes in physical properties of concrete from visual signs of honeycombs, chemical leaching and/or discoloration in concrete?

B.2.8 Reactor Vessel Internal Inspection Program

B.2.8-1 LRA Section B.2.8 indicates the reactor vessel internals inspection program will not include augmented inspection of bolting. Under "Operating Experience," the application indicates that the operating stresses are below 32 ksi and the local stress is approximately 66 ksi for shroud bolts. "Detection of aging effects," in XI.M16, "PWR Vessel Internals," of NUREG-1801 states:

> For bolted components, augmented ISI is to include other demonstrated acceptance inspection methods to detect cracks between the bolt head and the shank. Alternatively, the applicant may perform a component-specific evaluation, including a mechanical loading assessment to determine the

maximum tensile loading on the component during ASME Code Level A, B, C, and D conditions. If the loading is compressive or low enough (<5ksi) to preclude fracture, then supplemental inspection of the component is not required.

a. Indicate whether the mechanical loading assessment described above results in compressive stress or tensile stresses less than 5 ksi for all reactor vessel internals bolts. If the mechanical assessment does not satisfy these stress limits, identify the augmented inspection program to be instituted during the period of extended operation to preclude fracture of the bolting components.

b. The B.2.8 enhancement table identifies "Parameters Monitored" and "Detection of Aging Effects" as AMP criteria numbers 7 and 8, respectively. These criteria are normally numbered 3 and 4, respectively. Please confirm that the "Parameters Monitored" and "Detection of Aging Effects" criteria in the B.2.8 enhancement table are items 3 and 4 , respectively."

B.2.9 Steam Generator Program

B.2.9-1 The applicant stated that its steam generator integrity program is consistent with Section XI.M19, "Steam Generator Tube Integrity," in the GALL report. However, the GALL report provides only generic guidelines for the ten attributes. The GALL report states that the scope of XI.M19 is specific to steam generator tubes. Therefore, the applicant should address the following items as they relate to the steam generator tubes.

Preventive Actions

Section XI.M19 states that NEI 97-06, "Steam Generator Program Guidelines," was under staff review at the time GALL was developed. NEI 97-06 is still under staff review and has not been incorporated into the applicant's technical specifications. Therefore, please identify the preventive actions, including the use of water chemistry, that will be taken to mitigate degradation in the steam generators. Also, in the table on page B-3 of the LRA, it states that loose parts monitoring is not credited for aging management. Therefore, it is unclear to the staff why the steam generator program is being enhanced to write an annunciator response procedure for the loose parts monitor for the steam generator. Please clarify this apparent discrepancy.

Detection of Aging Effects

Because NEI 97-06 was under staff review at the time of issuance of XI.M19, the staff is unclear whether the guidance in this document will be implemented by the applicant. NEI 97-06 is still under staff review and has not been incorporated into the applicant's technical specifications. Therefore, please identify how aging effects will be detected, including the method or technique used to detect the aging effect, the inspection frequency and the sample size. Explain how these will ensure that the aging effect will be detected and corrected before the loss of the component's intended function.

Monitoring and Trending

Section XI.M19 states that condition monitoring assessments are performed to determine whether structural and accident leakage criteria have been satisfied. Operational assessments are performed after inspections to verify that structural and leakage integrity are maintained during the operating interval until the next inspection. NEI 97-06 guidelines and technical specifications are used to select the time of the next inspection. Because NEI 97-06 is still under staff review, the staff is unclear whether the guidance in this document will be implemented by the applicant. Please identify how condition monitoring and operational assessments are performed.

B.2.9-2 The applicant stated that the steam generator program is consistent with XI.M19, "Steam Generator Tube Integrity," in the GALL report, with the exception of two enhancements. The applicant stated that its steam generator program also includes aging management activities to address plant-specific AMP requirements identified in LRA Tables 3.1-1 and 3.1-2. However, the GALL report states that the scope of XI.M19 is specific to steam generator tubes. Therefore, please respond to the following related questions:

1. LRA Table 3.1-1, Row 3.1.1.02, "Steam Generator Shell Assembly," states that the aging effect for this component (i.e., loss of material due to pitting and crevice corrosion) is managed, in part, by the steam generator program (B.2.9). It is not clear to the staff how the steam generator program manages this aging effect. In addition, because the GALL report states that the scope of XI.M19 is specific to steam generator tubes, provide details for the following attributes for this component: Preventive Actions; Parameters Monitored/Inspected; Detection of Aging Effects; Monitoring and Trending; and Acceptance Criteria. Ensure that the discussion identifies how the steam generator program manages this aging effect (e.g., the part of this component that is managed by the steam generator program and how it is managed by the steam generator program).

2. LRA Table 3.1-1, Row 3.1.1.15, "(Alloy 600) Steam generator tubes, repair sleeves, and plugs," states that the aging effect for these components is managed, in part, by the steam generator program (B.2.9). The GALL report states that the scope of XI.M19 is specific to steam generator tubes; therefore, provide details for the following attributes for the repair sleeves and plugs: Preventive Actions; Parameters Monitored/Inspected; Detection of Aging Effects; Monitoring and Trending; and Acceptance Criteria.

3. LRA Table 3.1-1, Row 3.1.1.16, "Tube support lattice bars made of carbon steel," states that the aging effect for this component is managed by the steam generator program (B.2.9). The GALL report states that the scope of XI.M19 is specific to steam generator tubes; therefore, provide details for the following attributes for this component: Preventive Actions; Parameters Monitored/Inspected; Detection of Aging Effects; Monitoring and Trending; and Acceptance Criteria.

4. LRA Table 3.1-1, Row 3.1.1.17, “Carbon steel tube support plate,” states that the aging effect for this component is managed by the steam generator program (B.2.9). The GALL report states that the scope of XI.M19 is specific to steam generator tubes; therefore, provide details for the following attributes for this component: Preventive Actions; Parameters Monitored/Inspected; Detection of Aging Effects; Monitoring and Trending; and Acceptance Criteria.

5. LRA Table 3.1-2, Row 3.1.2.06, “Secondary side of the tubesheet, steam generator feedwater, steam and instrument nozzles, and feedwater nozzle safe ends,” states that the aging effect for these components is managed by the steam generator program (B.2.9). The GALL report states that the scope of XI.M19 is specific to steam generator tubes; therefore, provide details for the following attributes for this component: Preventive Actions; Parameters Monitored/Inspected; Detection of Aging Effects; Monitoring and Trending; and Acceptance Criteria.

6. LRA Table 3.1-2, Row 3.1.2.07, “Steam generator tube plugs,” states that the aging effect for this component is managed by the steam generator program (B.2.9). The GALL report states that the scope of XI.M19 is specific to steam generator tubes; therefore, provide details for the following attributes for this component: Preventive Actions; Parameters Monitored/Inspected; Detection of Aging Effects; Monitoring and Trending; and Acceptance Criteria.

7. LRA Table 3.1.2, Row 3.1.2.14, “Steam generator steam nozzle safe end, steam generator feed ring,” states that the aging effect for these components is managed by the steam generator program (B.2.9). The GALL report states that the scope of XI.M19 is specific to steam generator tubes; therefore, provide details for the following attributes for this component: Preventive Actions; Parameters Monitored/Inspected; Detection of Aging Effects; Monitoring and Trending; and Acceptance Criteria.

B.3.1 Alloy 600

B.3.1-1 Background

In NRC Bulletin 2001-01, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,” the staff summarized circumferential cracking that had occurred in control rod drive mechanism (CRDM) nozzle J-groove welds at the Oconee Unit 1 and Unit 3 nuclear stations, and emphasized the need for licensees who own pressurized water reactors (PWRs) to perform bare-surface visual examinations of their reactor vessel heads. In NRC Bulletin 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,” the staff summarized excess boric acid wastage that had occurred in the Davis Besse reactor vessel head as a result of leaking CRDM nozzles and excessive boric acid buildup on the head. The Davis Besse event indicates that boric acid wastage inspection programs implemented in accordance with staff requests in NRC Generic Letter 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,” may not, by themselves, be capable of effectively monitoring for and controlling leakage past CRDM or other vessel head penetration nozzles, or boric acid-induced wastage of the low-alloy steel reactor vessel heads that the penetration nozzles are welded to. Based on the Davis Besse event, in NRC Bulletin 2002-02, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,” the staff emphasized the need to perform augmented inspections of CRDM and other vessel head penetrations beyond the bare surface visual examinations of reactor vessel heads that were recommended in NRC Bulletin 2002-01.

In addition, other prominent PWSCC cracking events have occurred since January 2000. On October 7, 2000, during a containment inspection of the V. C. Summer nuclear plant after entering a refueling outage, the licensee identified a large quantity of boron on the floor and protruding from the air boot around the "A" loop RCS hot leg pipe. On October 12, 2000, a liquid penetrant test (PT) performed by the licensee indicated the existence of a 4-inch long circumferential indication in the first Alloy 82/182 weld between the reactor vessel nozzle and the "A" loop hot leg piping, approximately 3 feet from the reactor vessel. Additional non-destructive testing of the "A" loop hot leg piping did not confirm a flaw at the location of the circumferential indication. These tests identified, at a different location, an axial crack-like indication, approximately 2.7 inches long, and located approximately nine degrees counterclockwise from top dead center of the weld. This indication extends from approximately the centerline of the weld toward the reactor nozzle. Visual examination from the outside diameter of the pipe identified a small "weephole" in the center of the weld at approximately the same circumferential location as the axial indication. On this basis, to ensure that the proposed AMP will adequately manage the aging effects associated with this industry experience, the staff requests the following information:

1. The program elements addressed by this portion of the RAI are [Detection of Aging Effects], [Monitoring and Trending], [Acceptance Criteria] and [Corrective Actions]. On the basis of the issues raised in Bulletins 2001-01, 2002-01, and 2002-02, the staff is currently determining, with the U.S. nuclear power industry, what the requirements should be for inspections of vessel head penetration (VHP) nozzles in U.S. PWRs. The scope of any actions and/or activities agreed upon between the NRC and the industry for resolution of this issue will need to address acceptable criteria for the monitoring, detection, evaluation, and correction of potential cracking that occurs in the VHP nozzles of U.S. PWRs. Since this issue might not be resolved prior to issuance of the renewed operating license for FCS, the staff requests that the applicant commit to implement, as part of the Alloy 600 Program, any actions that are agreed upon between the NRC, Nuclear Energy Intitute (NEI), Materials Research Program (MRP), and the nuclear power industry, for the inspection, detection, evaluation (including the establishment of acceptable acceptance criteria for the VHP nozzle inspection techniques that are agreed on between the staff and the industry), and correction of cracking that may occur in VHP nozzles of U.S. PWRs, and specifically as the actions relate to ensuring the integrity of VHP nozzles in the FCS upper RV head during the period of extended operation.

2. The program elements addressed by this portion of the RAI are [Scope], [Detection of Aging Effects], [Monitoring and Trending], and [Operating

Experience]. The staff requests the applicant to identify the Alloy 600 and Alloy 82/182 locations in the FCS pressurizer, steam generators, and RCS piping. With respect to these locations, the staff requests that the applicant identify those locations that are most likely to develop PWSCC and those locations in which the applicant has already detected and reported leakage and/or indications of PWSCC. If leakage and/or PWSCC has been detected and reported in any of the Alloy 600 or Alloy 82/182 locations in the FCS pressurizer, steam generators, or RCS hot-leg piping, indicate whether applicable Section XI Code repairs have been made to the flawed areas or whether relief has been granted to use alternative repair or replacement methods for repairing the flawed areas (NOTE: if relief has been granted pursuant to 10 CFR 50.55a, and alternative repair/replacements have been implemented at FCS for these nozzles, appropriate TLAAs must be submitted for the alternative repair or replacement methods if long-term installation is to be implemented over the period of extended operation without the granting of multiple temporary reliefs by the NRC under the requirements of 10 CFR 50.55a). Additionally, the staff requests the applicant to describe the actions it plans to take for maintaining the integrity of these Alloy 600 and Alloy 82/182 locations over the period of extended operation for FCS. Include in your response a discussion of specific actions taken, if any, to resolve the V.C. Summer RCS hot leg cracking issue as it pertains to maintaining the structural integrity of RCS hot leg piping at FCS.

3. Pursuant to 10 CFR 54.21(c)(3), the next revision to the FSAR Supplement description for the Alloy 600 Program must reflect the applicant's response to GL 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," and NRC Bulletins 2001-01, 2002-02, and 2002-02. When submitted, the staff also requests that the applicant incorporate its responses to parts 1 and 2 of this RAI into applicant's next revision to the FSAR Supplement description for the Alloy 600 Program, since the responses to the RAIs will provide clarifying content as to how the Alloy 600 Program will be sufficient to manage cracking in ASME Code Class 1 components made from Alloy 600 or Alloy 82/182 materials (i.e., Inconel alloy materials).

B.3.2 Buried Surfaces External Corrosion Program

B.3.2-1 The applicant states that the buried surface external corrosion program will be consistent with GALL AMP XI.M34, "Buried Piping and Tanks Inspection." In order to determine whether this AMP will be adequate to manage aging effects associated with external surfaces of buried components, the staff requests the applicant to discuss the changes that will be made to the current program in order to make it consistent with the GALL AMP.

B.3.2-2 The detection of aging effects in buried components is plant-specific and depends on plant operating experience as well as industry operating experience. Therefore, the staff must further evaluate the applicant's operating experience and proposed inspection frequency. The staff requests the applicant to expand the discussion of this AMP to include a breakdown (system name, component, and percentage of total buried components) of the components in systems within the scope of the program, the inspection frequency, and the applicable operating experience. Specifically, the applicant should discuss how often these buried components have been excavated during the current operating term, for what reason they were excavated and, based on this operating experience, how often the components may be excavated during the period of extended operation. In addition, the applicant should discuss how activities used to assess component internal conditions can be used to assess the condition of the component exterior.

B.3.3 General Corrosion of External Surfaces Program

B.3.3-1 In the applicant's description of the preventive actions attributed to the program, the applicant stated that, "This program does not prevent aging." The staff recognizes that an aging management program may not prevent the occurrence of an aging effect. However, the program description should clearly describe how it will be used to manage aging effects. Therefore, the staff requests the applicant to describe what this program accomplishes (e.g. maintains coatings, sealants, and caulking) to prevent corrosion that could hinder the component's ability to function.

B.3.3-2 In its description of the monitored or inspected parameters, the applicant describes the methods that will be employed to detect signs of external corrosion, and conditions that could result in external corrosion. Although fluid leakage is identified as an indicator of a corrosive environment, the staff believes that other parameters, such as tank wall thickness, cracked sealant, or degraded coatings, are important to detect degraded surface conditions. Therefore, the staff requests the applicant to describe the parameters that detect degradation of surface conditions on components within the scope of this program, and provide justification why these parameters need not be included in this aging management program to manage aging of components within the program scope.

B.3.3-3 Detection of loss of material and cracking on the external surfaces of inaccessible components is not discussed in the program description. This is an important consideration in the staff's determination of the adequacy of this aging management program. Therefore, the staff requests the applicant to describe the methods that will be used to detect loss of material and cracking in locations that may be inaccessible, such as the bottom of a tank, and provide a justification for why these methods are not material to demonstrate adequate aging management for components within the scope of the program.

B.3.3-4 In its description of the monitoring and trending of aging effects, the applicant states that evidence of fluid leaks, significant coating damage or significant corrosion is documented. In order to determine whether the monitoring and trending of aging effects are adequate for this program, the staff needs more information regarding the extent of the documentation process. Therefore, the staff requests the applicant to provide more detail on this documentation process. For instance, are all inspections documented and the results trended, or are only significant findings documented using a corrective action process?

B.3.3-5 The applicant states that plant procedures provide criteria for determining the acceptability of inspected components. In order to determine whether the acceptance criteria are adequate to ensure that appropriate corrective actions are taken upon the discovery of aging, the staff needs to understand the basis for the acceptance criteria. Therefore, the staff requests the applicant to discuss the NRC or industry guidance and operating experience used to establish the acceptance criteria. Does the criteria incorporate Generic Letter 98-04, “Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After A Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment,” Information Notice 86-99, “Degradation of Steel Containments,” or Regulatory Guide 1.54, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants?”

B.3.3-6 The General Corrosion of External Surfaces Program as described in LRA Section B.3.3 of the LRA is credited for managing loss of material and cracking. The application states that these aging effects can be detected by visual observation and inspection of external surfaces, including evidence of leaking fluid for certain components that are not routinely accessible. The staff believes that inspection for evidence of leaking fluids also provides indirect monitoring of certain components that are not routinely accessible. The presence of fluid leakage from a component, however, would indicate that the component may not perform its intended function as a pressure boundary. Therefore, in order to determine whether this program will adequately manage the aging effects of inaccessible components, the staff requests the applicant to clarify whether the scope of systems listed in LRA Section B.3.3 includes components that are not routinely accessible and which rely on the indirect monitoring of fluid leakage. In addition, the applicant is requested to discuss the operating history of these components to demonstrate that the applicable aging effects will be adequately managed prior to the loss of their intended functions.

B.3.4 Non-EQ Cable Aging Management Program

B.3.4-1 LRA Section B.3.4 provides the aging management program (AMP) for electrical cables and connectors not subject to 10 CFR 50.49 and for the electrical cables used in instrumentation circuits not subject to 10 CFR 50.49. The LRA states that the non-EQ cables were purchased to the same requirements and specifications as those included in the EQ program and installed and qualified under the applicant’s 10 CFR 50.49 Environmental Qualification Program. Therefore, additional temperature and environmental data utilized to extend the qualified life of the EQ Program equipment and cables will be utilized to analyze and establish a service life for the non-EQ cables. Program element 3, “Parameters Monitored or Inspected,” of LRA Section B.3.4 notes that the FCS non-EQ cable program is not consistent with the GALL report, in that the program does not credit the inspections delineated within Section XI.E1 of the GALL report.

On the basis of its review of LRA Section B.3.4, the staff is unclear how the proposed aging management program will manage aging of electrical cables and connections that are within the scope of license renewal and subject to an AMR, but that are not subject to 10 CFR 50.49 environmental qualification requirements (including those used in instrumentation circuits as well as inaccessible medium voltage cables). Specifically:

1. how will the Non-EQ aging management program manage aging in accessible and inaccessible electrical cables and connections that are within the scope of license renewal and subject to an AMR, but that are not subject to the environmental qualification requirements of 10 CFR 50.49 and that are exposed to adverse localized conditions caused by heat, radiation, or moisture, such that the cables and connectors will perform their intended functions in accordance with the current licensing basis through the period of extended operation?

2. how will the Non-EQ aging management program manage aging in accessible and inaccessible electrical cables that are within the scope of license renewal and subject to an AMR and that are exposed to adverse localized conditions caused by heat, radiation, or moisture, and that are used in circuits with sensitive, low-level signals, but that are not subject to the environmental qualification requirements of 10 CFR 50.49, such that the cables will perform their intended functions in accordance with the current licensing basis through the period of extended operation?

3. how will the Non-EQ aging management program manage aging in inaccessible medium-voltage electrical cables that are within the scope of license renewal and subject to an AMR and that are exposed to adverse localized environments caused by moisture while energized, but that are not subject to the environmental qualification requirements of 10 CFR 50.49, such that the cables will perform their intended functions in accordance with the current licensing basis through the period of extended operation?

B.3.6 Selective Leaching Program

B.3.6-1 As stated in LRA Section B.3.6, because of the lack of acceptance criteria, the applicant has removed from its inspection program the hardness testing specified in the GALL program. The selective leaching program in GALL specifies hardness measurement as a method for determining the degree of degradation of the components caused by selective leaching. It is considered to be a complementary method to the visual inspection. Trending hardness measurements could be helpful in estimating degradation of a component due to leaching in the case where visual inspection is ineffective. Therefore, the staff requests the applicant to describe how the degradation due to leaching can be evaluated without hardness measurements, particularly in the case where visual inspection cannot produce meaningful results.

B.3.6-2 LRA Table 3.3-2, Item 3.3.2.43, credits the selective leaching program (B.3.6) for managing aging of buried copper or zinc-alloy tubing. The LRA states that AMP B.3.6 is consistent with GALL XI.M33, “Selective Leaching of Materials,” which includes a one-time inspection of selected components. Because buried tubing made of copper-zinc alloy was not evaluated in GALL, the staff needs to understand how AMP B.3.6 will be used to manage aging in accordance with XI.M33. In particular, the staff is unclear how the one-time inspection referenced in XI.M33 will be implemented for this component. On this basis the staff requests the applicant to discuss how a one-time inspection will be used to manage aging in this component.