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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.

Response:

The following methodology was utilized to address the issue.

1. Non-safety related systems with the potential for adverse spatial interaction with safety-related SSCs were identified as follows:

   - Reviewed LRA boundary drawings
   - Reviewed boundary drawings beyond the scope of the LR boundaries

- Reviewed plant level scoping and screening
- Reviewed systems and their drawings for identified systems that were not within the scope of license renewal
- Performed walkdowns
- Reviewed piping plan and elevation drawings to determine the potential for interference of non-safety-related SCs with safety-related SCs (Physical drawings were used in lieu of walkdowns for some areas of the evaluation. This was felt to be a satisfactory means for this determination due to the detail provided on the drawings.)

2. In addition to seismic II/I systems, all non-seismic systems containing steam or liquid were included unless specific justification existed for their exclusion, such as a location remote from susceptible safety related SSCs.

   - Identified systems containing steam or liquid

   Due to operating experience at FCS and in the industry, it was determined that air and gas systems need not be included in this evaluation. No failures were found due to aging that could prevent safety-related equipment from performing their functions.

3. Applicable aging management programs (AMPs) for the identified systems were the FAC Program, the General Corrosion of External Surfaces Program, the Chemistry Program, and the Structures Monitoring Program.

   - An Engineering Analysis (EA) was generated to document the results of the evaluation
   - The scoping and screening evaluation was incorporated into the results of the EA

4. A review of site and industry operating experience was performed.

   - FCS operating experience was reviewed for FAC failures
   - Industry operating experience as documented in SOERs, NRC Bulletins, NRC Information Notices (INs), Generic Letters, and INPO O&MRs was reviewed
   - The results of the AMR were incorporated in the EA

5. The systems having components found to have met the 10 CFR 54(a)(2) criterion for spatial interaction were as follows:

   - Auxiliary Feedwater*
   - Component Cooling Water*
   - Chemical and Volume Control *
   - Fire Protection*
   - Feedwater*
   - Liquid Waste*
   - Main Steam*
   - Raw Water*
   - Reactor Coolant*
   - Spent Fuel Pool Cooling*
   - Safety Injection*
   - Steam Generator Blowdown*
   - Auxiliary Steam

- Condensate Return
- Chemical Feed
- Demineralized Water
- Primary Plant Sampling
- Potable Water
- Service Water

* - These systems were already within scope for license renewal.

6. Programs identified to manage AERMs for these systems, as applicable:

- Flow Accelerated Corrosion
- Chemistry
- General Corrosion of External Surfaces
- Structures Monitoring

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.

Response:

The FCS Quality Assurance Plan implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Section A.2 of NUREG 1800, *Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants*, published July 2001. The Quality Assurance Plan includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and non-safety-related structures, systems, and components that are within the scope of license renewal.

Corrective action is initiated upon identification of conditions adverse to quality through the FCS Condition Report system. This includes review for significance, cause determination, corrective

actions, prevention of recurrence, and trending. The FCS QA Plan provides for control over activities affecting the quality of systems, structures and components consistent with their importance to safety. Confirmation is achieved through review of proposed corrective actions for significant conditions adverse to quality by the FCS Plant Review Committee.

Activities affecting safety are described by written procedures of a type appropriate to the circumstances and are accomplished in accordance with these instructions and procedures. These procedures include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

2.1-3

Long-Term Implementation

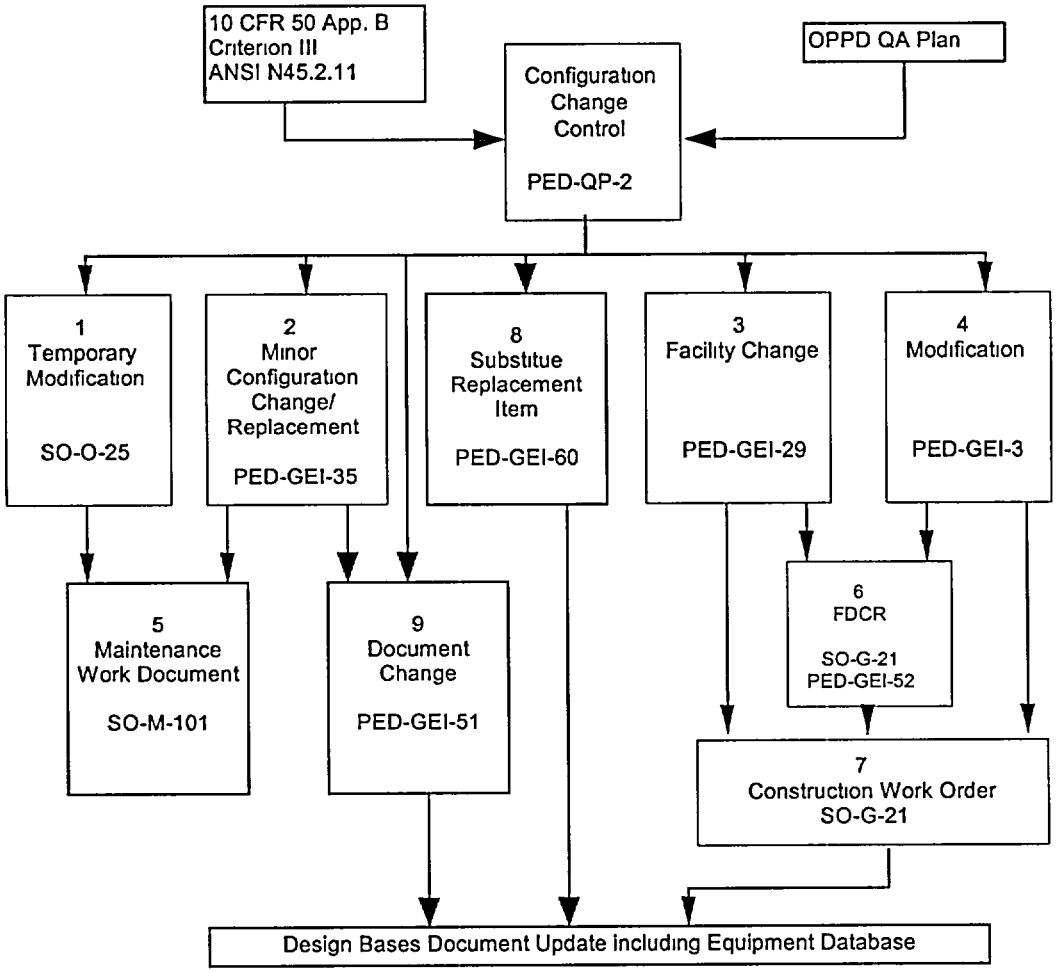
During the audit of the FCS scoping and screening methodology, the audit team determined that the procedures reviewed, in combination with the review of a sample of scoping and screening products, provided adequate evidence that the scoping and screening process was conducted in accordance with the requirements 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."

Background to Response:

The plant equipment design basis is documented on the plant drawings and in the FCS equipment database. Instructions for maintaining the plant equipment design base are included in PED-GEI-56, *Configuration Change Closeout*; PED-GEI-47, *Fort Calhoun Equipment Database Control*; and PED-GEI-38, *P&ID/EM Drawing Issuance Instruction.*

The OPPD engineering design and configuration control processes for FCS are designed to ensure configuration changes and document changes are conducted in accordance with applicable rules and regulations including the requirements of 10 CFR 50, Appendix B, Criterion III. These processes are depicted in Figure 1.

Figure 1
Engineering Design and Configuration Control Processes



1. Temporary Modification: Short term alteration to the Plant that involve changes to the design bases.
2. Minor Configuration Change/Replacement Simple changes that do not affect design parameters, operating conditions or functions
3. Facility Change: Changes to non-CQE systems, structures or components that do not affect safety related design parameters, operating conditions, or functions
4. Modification: A change to the form, fit, or function of a CQE or Limited CQE system, structure or component

5. Maintenance Work Document: Authorize, document and control maintenance work activities
6. Field Design Change Request: Field change to an approved design change package
7. Construction Work Order: Authorize, document and control construction work activities
8. Substitute Replacement Item: Authorize and document the equivalency for the replacement of a part or component that does not have the same make, model and/or part number as the original.
9. Document Change: update of existing documents to reflect as-built conditions

The following processes are used to make configuration changes to FCS plant systems, structures and components:

1. Modification,
2. Facility Change (FC),
3. Minor Configuration Change or Replacement (GEI-35),
4. Temporary Modification (TM), and
5. Substitute Replacement Item (SRI).

The Substitute Replacement Item Engineering Change Notice (SRI) and the Document Change Engineering Change Notice (DC) are processes used to revise design bases documents without changing the form, fit or function of the FCS systems, structures, and components.

Modification

Standing Order SO-G-21, *Modification Control*, establishes procedural guidance for initiating, reviewing, approving and canceling Modification Requests. Modifications generally involve changes to the station that are complex from a system interaction perspective and affect system design parameters as well as operating conditions. The modification process must be used for any configuration change that involves:

1. a change, directly or indirectly, to the fit, form or function of a CQE or a limited CQE system, structure, or component, or
2. a change to a non-CQE system, structure, or component that affects a CQE or a limited CQE system, structure, or component.

Modifications are documented in a Design Change Package (DCP) in accordance with PED-GEI-3, *Preparation of Modifications*. Included in the DCP is a System Interaction Analysis. System Interaction Analyses are used to determine the impact of a modification on plant level design bases. Checklists are used to screen a modification for the following potential system and plant interactions:

1. Fire Protection
2. Special Service Engineering Programs
3. Motor Operated Valve Program
4. Electrical Equipment Qualification
5. High Energy Line Break
6. Seismic Interaction, Qualification, and Effect on the USI A-46 Program
7. Electrical System Analysis
8. Human Factors Review
9. Security System
10. Environmental and Radiological Release
11. Materials Compatibility
12. Containment Integrity
13. Control Room Habitability
14. Missile Protection
15. Structural Impact
16. Independence Criteria

17. Single Failure Criteria
18. Possibility of Operator Error
19. Heavy Loads
20. Impact on HVAC
21. Use of Vendor Procedures
22. Station Blackout

This analysis confirms that the modification conforms to the design bases.

Facility Change

The Facility Change allows simple configuration changes to FCS equipment and supporting facilities. These changes:

1. Do not directly or indirectly affect CQE or limited CQE systems, structures or components,
2 Do not affect the Technical Specifications, and
3. Do not directly or indirectly affect nuclear safety.

Facility Changes are documented in accordance with PED-GEI-29, *Preparation of Facility Changes*. The Facility Change provides the information necessary to construct and test the configuration change. The Facility Change also includes a Systems Interaction Analysis.

Minor Configuration Change or Replacement

A Minor Configuration Change or Replacement is a change to the facility that does not alter the design, function, or method of performing the function of a component, system, or structure described in the Safety Analysis Report. A Minor Configuration Change or Replacement does not require detailed engineering and is simplistic in character.

A 10 CFR 50.59 screening evaluation is required to demonstrate a minor configuration change or replacement does not alter the design, function, or method of performing the function of a component, system, or structure described in the Safety Analysis Report.

A Minor Configuration Change or Replacement is documented in accordance with PED-GEI-35, *Preparation of Minor Configuration Changes*. A Minor Configuration Change or Replacement includes a Systems Interaction Evaluation.

A Minor Configuration Change or Replacement is installed and tested using a Maintenance Work Document (MWD). Post-maintenance testing requirements are specified within the MWD. Documents that require updating as a result of the change (e.g., drawings, procedures, manuals, database, etc.) are updated using a Document Change.

Temporary Modifications

Temporary Modifications (TM) are temporary minor alterations made to plant equipment that do not conform with original drawings or other design documents. These alterations are temporary in that they are expected to be installed for a short duration.

Substitute Replacement Item

A SRI is used to conduct and document an engineering equivalency evaluation of replacement parts or components that do not have the same make, model and/or part number as the original. This evaluation ensures that interface, interchangeability, safety, fit, and function requirements are maintained in accordance with applicable regulatory or code requirements. The SRI-ECN Equivalency Evaluation performed per PED-GEI-60, *Preparation of Substitute Replacement Items,* demonstrates that the Substitute Replacement Item is being procured to an equivalent specification. If equivalency cannot be demonstrated, then a SRI is not applicable.

Response:

To ensure the aging management review process is appropriately applied to structures, systems and components (SSCs) at FCS, it will be integrated into the existing plant equipment design basis and engineering design and configuration control process (The aging management review process is defined as the identification of SSCs subject to aging management review, the identification of applicable AERMs, and the determination of the aging management programs required for aging management).

To reflect the results of the aging management reviews conducted to prepare the FCS LRA, appropriate drawings will be annotated to identify the scope of equipment subject to aging management review, and the FCS equipment database will be revised to include identification of equipment subject to aging management review.

With the issuance of the renewed license, aging management becomes part of the FCS design basis and will be treated similar to other design basis requirements. To integrate the aging management review process into the engineering design and configuration control processes, the following are envisioned:

- Develop guidance for scoping and screening of FCS configuration changes to identify equipment subject to aging management review.
- Develop guidance for the conduct of an aging management review of equipment included in FCS configuration changes.
- Utilize the systems interaction analyses and evaluations for modifications, facility changes and minor configuration changes or replacements to identify the requirement to conduct scoping and screening. Scoping and screening would identify the requirement to conduct an aging management review.

Existing duration and applicability limitations for temporary modifications and substitute replacement items preclude these configuration change processes from affecting existing aging management review results or requiring additional aging management review.

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.

Response:

As a general comment, 10 CFR 54.21, Contents of Application, does not require the application to identify in the LRA the criterion by which a component ultimately ends up being in scope for LR and subject to aging management review. It focuses only on those SCs subject to aging management review. The component-by-component identification of the criteria by which SSCs are within scope for license renewal is contained in the individual system LR Engineering Analyses (EAs) that are available for inspection at the Fort Calhoun site.

Relative to PTS, the reactor vessel belt line plates and welds (see LRA Table 2.3.1.3-1, component type RV Closure Head, RV Lower Shell, RV Middle Shell, RV Bottom Head, RV Flange, and associated cladding) are the only SSCs included within the scope of LR for PTS.

Relative to ATWS, as described on page 2-9 of the application and shown in Table 2.2-1 (page 2-19 of the application), the Diverse Scram System (DSS) and its structures and components are within the scope of LR for ATWS. The design and installation of the DSS meet the requirements found in 10 CFR 50.62(c)(1) and (2). As stated in Section 2.5.17 of the LRA, the DSS components include actuating relays, blocking relays, indicating lights, alarm logic, pressure sensors, power supplies, and miscellaneous electronic components, which are within scope of license renewal (see Section 2.5.17 on page 2-130 of the application). These components were classified as active, consistent with the Guidance in NEI 95-10, Rev. 3, and, therefore, not subject to AMR.

2.2 Plant-Level Scoping Results

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.

Response:

The LR boundary drawings were created as information only documentation to facilitate NRC's review of the FCS Application. There was never any intent to maintain and control these drawings. FCS will comply with 10 CFR 54.37(b) by including a LR designation in the plant equipment database for components within the scope of LR but will not maintain the LR boundary drawings.

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.

Response:

The pressurizer spray function (linked to AMR Results Items 3.1.1.01, 3.1.1.10, 3.1.1.11, 3.1.1.21, 3.1.1.25, and 3.1.2.02) is one of three methods relied upon for RCS pressure reduction and subsequent cooldown. In the event of a fire followed by a reactor trip, the auxiliary spray system (which uses the pressurizer spray head supplied by CVCS) or the power-operated relief valves may be used to depressurize the RCS. In the event that these two methods are unavailable, primary system depressurization is accomplished by RCS charging and sufficient secondary decay heat removal via the steam generator safety valves and auxiliary feedwater system. All SSCs associated with these depressurization methods are within scope of LR and all of these that are passive and long-lived are subject to AMR.

It has been determined that the spray nozzle pattern is not credited for the pressure reduction that is accomplished during spray function activation. The analysis only takes credit for the volume of water added to the pressurizer steam bubble through the spray nozzle. The generation of a spray pattern by the spray nozzle is not, therefore, a LR intended function.

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.

Response:

The RCP lube oil collection subsystem is included within scope of license renewal and addressed in Table 2.3.3.14-1, Fire Protection, under the component types Pipes & Fittings, Piping Spray Shield, and Pressure Vessels. The applicable components are linked to AMR Results Item 3.3.2.73.

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.

Response:

The FCS flow limiters are of the venturi type and are built into the piping downstream of the first elbow in the horizontal Main Steam System piping runs leaving the steam generators. For LR, they are treated as part of the piping in which they are contained. This piping, including the limiters, is included in Table 2.3.4.3-1, Main Steam and Turbine Steam Extraction, under the component type Pipes & Fittings: however, since the venturis are fabricated of Inconel, there are no AERMs in the steam environment.

The flow limiters are credited for a main steam line break by limiting the cross sectional area equivalent to fifty percent of that of the inside diameter of the main steam piping such that steam flow is restricted to less than 11×10^6 pounds per hour following a main steam line break incident. An intended function of "Flow Restriction" has been added to Table 2.3.4.3-1. Because there are no AERMs, there is no AMP needed to manage the venturi throat diameter.

2.3.1.3 Reactor Vessel

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.

Response:

The leakage detection lines, or closure head vent lines, have been included within scope of license renewal and are addressed in Table 2.3.1.3-1 under the component type Pipes & Fittings, CEDM Housings. The applicable components are linked to AMR Results Items 3.1.1.01, 3.1.1.06, and 3.1.1.24.

2.3.2.1 Safety Injection and Containment Spray

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.

Response:

The containment spray ring and nozzles are within scope of license renewal as shown on Dwg. E-23866-210-130, Sheet 2, in zones B, C, D – 1, 2, 3 and are included in Table 2.3.2.1-1 under the component type Pipes & Fittings. The applicable components are linked to AMR Results Items 3.2.1.01, 3.2.1.10, and 3.2.2.04.

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.

Response:

The raw water pumps do not require forced ventilation from the intake structure HVAC system to perform their intended function.

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.

Response:

The borated water filter housing is not in scope for license renewal because the filter is not used. Its isolation valves are normally closed. Drawing E-23866-210-121, Sheet 2, has been revised to show valves CH-131 and CH-134 (the filter isolation valves) as normally closed. A copy of this drawing has been provided with the Reference 5 letter.

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)

Response:

The expansion joints and mufflers are included in Table 2.3.3.3-1 under the component type Pipes and Fittings. They are managed for aging per the AMR Results Items listed for the component type.

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)

Response:

Drawing E-4183 is applicable to the diesels themselves and not the diesel Ventilating Air System. Refer to the note at location D-4 on Ventilating Air electronic boundary drawing VA56299R05or11405-M-97Sh2. This note indicates that the radiator cooling ductwork is included in the license renewal boundary. This ductwork is included in LRA Table 2.3.3.13-1, Ventilating Air, and managed for aging per AMR Item 3.3.1.05.

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)

Response:

The air box drain drums are within scope of license renewal and are covered under the component type Tanks in Table 2.3.3.4-1. They are managed for aging per LRA AMR Items 3.3.1.05 and 3.3.1.07.

The camshaft counter weight housing is considered to be part of the engine. For this reason, it is considered to be active and not subject to AMR.

2.3.3.5 Auxiliary Boiler Fuel Oil and Fire Protection Fuel Oil

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.

Response:

Hoses and hose couplings identified in LRA Table 2.3.3.5-1 are inspected for fraying, cracking, splitting, embrittlement, corrosion damage, or degradation which could prevent them from performing their intended function. This inspection is performed per approved plant procedures in accordance with the Periodic Surveillance and Preventive Maintenance Program (B.2.7) in Appendix B of the application). Condition determination is made by craft and engineering judgement and, if necessary, the hose and/or couplings are replaced based on condition in accordance with the Corrective Action Program.

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.

Response:

The instrument manifolds are subject to AMR and are included under the component type Pipes & Fittings in Table 2.3.3.6-1. They are managed for aging in accordance with LRA AMR Items 3.3.2.29 and 3.3.2.30. Item 3.3.2.30 has been added to this table.

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.

Response:

Not all filters shown on the drawing are in scope. For example, the oil removal filters, SA-2-2-F, are not in scope as shown on B120F07001, Shts. 1 & 2. The filters that are in scope, as shown on these drawings, are included in LRA Table 2.3.3.7-1 under component type Filters/Strainers. They are managed for aging per the LRA AMR Items listed for the component type.

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.

Response:

Sub-system (2) nuclear detector well cooling SCs should be in scope for license renewal and subject to an AMR; therefore, they will be included in Component Types "Blowers & Fan Housing," "Filter Housing," "Dampers," "Duct," "Heat Exchangers," and "Pipes and fittings" of

Table 2.3.3.10-1. P&ID 11405-M-1, Sheet 1 has been corrected and was provided with the Reference 5 letter.

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.

Response:

OPPD has treated ventilation dampers in the same manner that valves are treated. They are subject to AMR due to the pressure boundary function provided by their bodies/housings. This is indicated by the "Pressure Boundary" intended function for the Dampers in LRA Table 2.3.3.10-1 and the other ventilation system scoping and screening results tables.

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.

Response:

OPPD has treated ventilation fans/blowers in the same manner that pumps are treated. They are subject to AMR due to the pressure boundary function provided by their casings/housings. In LRA Table 2.3.3.10-1, Blowers & Fan Housings are shown as subject to AMR for a "Pressure Boundary" intended function. The blowers and fan housings for all ventilation systems within the scope of license renewal have been treated the same way.

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.

Response:

The boundary flag on drawing 11405-M-2, Sh. 2 was in error. The components downstream of HCV-824B, -825B, and -826B are not in scope. The boundary flag has been corrected and a revised copy of the drawing was provided with the Reference 5 letter.

Relative to dampers, see the response to 2.3.3.10-2 above.

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.

Response:

The MCRE consists of the main control room area, including shift supervisors office, lunch room and mezzanine area, computer room, mechanical equipment room and elevator machinery room. All control room ventilation SCs inside and outside the MCRE are identified and within scope for license renewal and subject to AMR. Housings for components listed in the RAI question are included within the Component Types "Blower & Fan Housing," "Filter/Strainers," and "Dampers." These housings are subject to AMR for a "Pressure Boundary" intended function consistent with the response to 2.3.3.10-3 above.

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.

Response:

Elastomer (neoprene) seal and flex connections in the Control Room HVAC System are in scope for license renewal and subject to AMR, and are linked to LRA Table 3.3.1.02. Fire barrier penetration seals used to maintain the MCRE boundary are in scope for license renewal and subject to AMR. These fire penetration barriers are located in LRA Table 2.4.2.1-1, Auxiliary Building, and are linked to LRA Table 3.3.1.19.

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.

Response:

As shown in Table 2.3.3.13-1, there are no fans within the scope of license renewal for this system; however, where fans are installed in other ventilation systems and within scope of license renewal, their housings have also been included in scope just like pump casings are in scope for within scope of license renewal pumps. See Tables 2.3.3.10-1, 2.3.3.11-1, and 2.3.3.12-1.

2.3.3.14 Fire Protection

2.3.3.14-2 [Note: The responses to parts a. and b. of this RAI were included in the Reference 4 letter.]

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

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 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

[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...."

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.

Response:

The transformer deluge piping downstream of the deluge valve has been included in scope for license renewal and is subject to AMR. The piping is included in LRA Table 2.3.3.14-1, Component Type "Pipes & Fittings" and linked to LRA AMR Items 3.3.1.05, and 3.3.2.94. Valves are included in Component Type "Valves" and linked to LRA AMR Items 3.3.1.20 and 3.3.2.10. The spray nozzles are included in Component Type "FP Sprinkler/Spray Nozzles," and linked to LRA AMR Item 3.3.2.40. Revised drawings 11405-M-266, Sh. 1A and Sh. 8A have been provided with the Reference 5 letter.

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.

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.

(Note RAI typographical error: The first paragraph, third sentence should read, "...the fire alarm pressure switch...")

Response:

The wet pipe suppression system retard chambers for the Radwaste Processing Building have been included in scope of license renewal and are subject to AMR. Piping is included in LRA Table 2.3.3.14-1, Component Type "Pipes & Fittings" and linked to LRA AMR Items 3.3.1.05, and 3.3.2.94. Valves are included in Component Type "Valves" and linked to LRA AMR Items 3.3.1.20 and 3.3.2.10. The retard chambers are included in Component Type "Tank" and linked to LRA AMR Items 3.3.1.05 and 3.3.1.20. Revised Drawing 11405-M-266, Sh. 11 was provided by the Reference 5 letter. The suppression systems depicted on Drawing 11405-M-266, Sh. 12 are not included in the New Radwaste Processing Building at FCS (see Fire Hazards Analysis, EA-FC-97-001, Rev. 3 page 258); therefore, they are not included within scope of license renewal.

e. 11405-M-259, Sheet 1 - Fire Protection Jockey Pump

(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.

Response:

The jockey pump casing, discharge isolation valve, and various trim valves as appropriate, including the strainer, have been included within scope of license renewal and are subject to AMR. Piping is included in LRA Table 2.3.3.14-1, Component Type "Pipes & Fittings" and linked to LRA AMR Items 3.3.1.05 and 3.3.1.20. The pump is included in Component Type "Pump Casings" and linked to LRA AMR Items 3.3.1.05 and 3.3.1.20. Valves are included in Component Type "Valves" and linked to LRA AMR Items 3.3.1.05, 3.3.2.10, and 3.3.1.20. Strainers are included in Component Type "Filters/Strainers" and linked to LRA AMR Items 3.3.1.05 and 3.3.1.20. LRA Item 3.3.1.20 has been revised to read "...raw water and potable water at FCS." A revised drawing 11405-M-259, Sh. 1 was provided with the Reference 5 letter.

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.

Response:

Fire hydrants are included in the Component Type "Valve Bodies" in LRA Table 2.3.3.14-1 and are, therefore, within scope of license renewal.

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.

Response:

The Turbine Generator Exciter CO_2 system is not in scope for license renewal because the system was installed to satisfy property liability concerns raised by American Nuclear Insurers (ANI) during an inspection in 1990. Furthermore, a fire in the turbine generator exciter housing will not challenge the 3 hour rated barrier separating the Turbine Building from the Auxiliary Building, nor will a fire challenge the ability to safely shut down the plant. As stated in the FCS Fire Protection Safety Evaluation Report, dated August 1978, Section 5.29, Turbine Building, Item 4, Fire Protection Systems, "The NRC reviewed fire barriers separating this area from safety-related areas and found it is adequate to prevent a fire in this area from exposing safety-related systems/components." Additionally, the Staff found, "...that the fire protection for this area satisfies the objectives identified in Section 2.2 of this report and is, therefore, acceptable." Based on the information provided above, OPPD finds that the CO_2 system in the Turbine Generator Exciter is not within scope for license renewal.

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.

Response:

Fire hoses are inspected and replaced based on condition in accordance with NFPA 1962, "Standard for the Care, Use and Service Testing of Fire Hose Including Couplings and Nozzles." Approved plant procedures in the Fire Protection Program (B.2.5 in Appendix B of the application) implement the guidance contained in NFPA 1962.

2.3.3.16 Component Cooling

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)."

Response:

Drawing 11405-M-119 incorrectly identified the CEDM Seal Housing Assemblies as being included within the Reactor Vessel Internals "system." They are actually included with the Reactor Vessel (RV). The drawing has been corrected and was provided with the Reference 5 letter.

The CEDM Seal Housing Assembly Coolers are within license renewal scope, but were inadvertently omitted during the IPA. They have been added to the FCS IPA. Drawing CND-E-2935, Seal Housing Assembly Details, was provided by the Reference 5 letter to show the configuration of this "cooler." It consists of a machined depression in the housing over which a nippled sleeve is fitted and welded into place such that a cooling water channel is created. The drawing is not a LR Boundary P&ID.

The CEDM Seal Housing Assembly is a subcomponent within the Component Type 'Pipes and Fittings, CEDM Housings' in Table 2.3.1.3-1 of the LRA. It is fabricated of austenitic stainless steel, has an internal environment of borated, treated water >482 deg F, and an external environment of containment air. A further subcomponent to this assembly has been added to the FCS IPA. The new subcomponent is the CEDM Seal Housing Assembly Cooling Channel. It has only an internal environment of nitrite-corrosion-inhibited, treated water (component cooling water). Its external environment is the external environment of the housing assembly itself. The AMPs credited for aging management of the cooling channel are the Chemistry Program and Cooling Water Corrosion Program. Links to LRA AMR Items 3.3.3.13 and 3.3.3.15 have been added to the "Pipes and Fittings, CEDM Housings" Component Type in Table 2.3.1.3-1 of the LRA.

These Seal Housing Assembly Coolers have only a pressure boundary function for the CCW System. They do not have an intended function of heat transfer because the cooling is only important to CEA driving or holding. It is not required for proper operation of the scram latches, which are needed for safe shutdown.

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.

Response:

The three vendor drawings (703741-001, 800997-001, and 801104) for the within scope radiation monitors have been provided with the Reference 5 letter.

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.

Response:

The Steam Generator Blowdown System is within scope of license renewal as noted in Table 2.2-1; however, a link was not provided to a system component type screening table as was done for the other in scope systems because the system has been evaluated within other in scope systems. The Steam Generator Blowdown System component type screening results have been included with the applicable component types listed in Table 2.3.1.2-1, Reactor Coolant (includes SGs); Table 2.3.2.2-1, Containment Penetration and System Interface; Table 2.3.3.19-1, Primary Sampling; and Table 2.3.4.1, Feedwater.

The Steam Generator Blowdown Nozzles are included in Table 2.3.1.2-1 under that component type.

The blowdown containment isolation valves and the penetration piping between the containment isolation valves are included in Table 2.3.2.2-1 under the component types Pipes & Fittings and Valve Bodies and are shown on electronic boundary drawing MCP10459R85or11405-M-253Sh1.

The steam generator blowdown sample piping and valves up to the outboard containment isolation valve are included in Table 2.3.3.19-1 under the component types Pipes & Fittings and Valve Bodies and are shown on electronic boundary drawings SLPRI10442R63or11405-M-12Sh1 and SLPRI10459R86or11405-M-253Sh1. The steam generator sample side of the sample coolers is within scope of license renewal to preserve the pressure boundary function of the CCW System.

The additional within scope piping and valves associated with steam generator blowdown are included in Table 2.3.4.1-1 under the component types Piping & Fittings and Valve Bodies and are shown on electronic boundary drawing FW10459R86or11405-M-253Sh1.

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.

Response:

OPPD has followed the guidance provided in Appendix B of NEI 95-10, Revision 3 (endorsed by NRC), for indicators (Item 89), switches (Item 102), including pressure and level switches, and transmitters (Item 105), including pressure and level transmitters, and scoped these as active components that do not require AMR.

Appendix B of NEI 95-10 is explicit regarding electrical and I&C components that need to be subject to AMR due to a pressure boundary function, as applicable. These are electric heaters (Item 81) and sensing elements (Item 84) such as RTDs, conductivity sensors, vibration sensors, etc.

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.

Response:

The turbine casing for the steam driven auxiliary feedwater pump has been included in the Auxiliary Feedwater System. See Table 2.3.4.2-1 of the LRA. The "Turbine Casing" Component Type and the links to its AMR Results are included in that table.

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."

Response:

The steam traps that are within scope of license renewal on the referenced drawing are included under the Component Type "Valves" in Table 2.3.4.3-1 of the LRA.

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.

Response:

Strainer ST-32, AFWP Steam Chest Supply Strainer, is within the scope of license renewal as shown on the referenced drawing in zone C5.

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.

Response:

The function of the tendon gallery is to provide access to the tendon anchorage for inspection and testing. The concrete structure of the tendon gallery does not provide support for Containment, and does not make up part of the pressure boundary of Containment (i.e., it is not required to prevent or mitigate the consequences of an accident that could result in potential offsite exposure). Therefore, it is not in scope for license renewal (i.e., it has no intended function per 10CFR54.4). However, the concrete where the tendons are anchored in the tendon gallery is within scope for license renewal.

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.

Response:

Refer to LRA Table 2.4.1-1. For the "Containment Equipment Access Hatch and Personnel Air Lock" entry, one of the Aging Management Review Results links is made to LRA AMR Item 3.5.1.05 which addresses the wear of the locks, hinges, and closure mechanism.

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.

Response:

Containment concrete above grade consists of the containment dome and cylindrical walls that are exposed to the weather. Containment concrete below grade consists of the mat foundation and parts of the cylindrical walls that are below grade. Containment concrete in ambient air consists of all interior containment structures (e.g., floors, reactor cavity, and missile shields), the portion of the containment cylindrical walls which are protected from the weather by the Auxiliary Building, and the inside of the containment dome and cylindrical walls.

The refueling cavity walls, containment sumps, and missile shields are included in the component type "Containment Concrete in Ambient Air."

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.

Response:

"Containment Structural Steel in Ambient Air" includes columns/posts, beams, baseplates, bracing, crane girders, platform hangers, checkered plate, decking, grating, stairs, ladders, ladder cages, whip restraints, pipe rupture shields, radiant energy shields, masonry wall external reinforcement, and exposed faces of embedded plates/structural shapes. All of these components are within scope of license renewal and subject to 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.

Response:

The fuel transfer tubes, expansion bellows and flange supports are included in LRA Table 2.4.2.5-1. They are in scope for license renewal and are subject to AMR.

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.

Response:

The cranes that are in scope for license renewal and subject to AMR are included in LRA Table 2.4.2.5-1.

The following is a list of the subcomponents that are passive and long-lived (i.e., in the scope of license renewal): crane/trolley rail systems, hoist monorails, and structural members used for the support of the crane bridge and trolley. The component types in LRA Table 2.4.2.5-1 associated with cranes or similar lifting devices represent only those subcomponents that are in the scope of license renewal and subject to AMR.

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.

Response:

These special structures are the cradle assemblies that support the steam generators. They are included in the component type "Component Support Weathering Carbon Steel in Ambient Air" in LRA Table 2.4.2.6-1 and are managed for aging per AMR Items 3.5.1.27 and 3.5.1.28. OPPD structural drawings E-23866-321-020 and E-23866-321-210 that show these assemblies have been provided by the Reference 5 letter.

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.

Response:

The structural drawings for the above referenced buildings were not marked up with LR boundaries and forwarded with the other LR Boundary drawings because Sections 2.4.1, 2.4.2.1, and 2.4.2.2 of the LRA indicate that the above structures are within the scope of license renewal. This means that every portion of these buildings identified on their respective structural drawings is within the scope of license renewal.

In addition to drawings provided during Scoping and Screening Inspection Audit, OPPD drawings 11405-A-257, -258, -259, -260, -261, -266, and 11405-S-309 have been included with the Reference 5 letter.

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.

Response:

The spent fuel pool concrete is included in the component type "Auxiliary Building Concrete in Ambient Air" in LRA Table 2.4.2.1-1, Auxiliary Building.

The spent fuel racks are included in the component type "Spent Fuel Storage Racks" in LRA Table 2.4.2.5-1, Fuel Handling Equipment and Heavy Load Cranes. Also included in this table are the component types, "Fuel Transfer Conveyor" and "Fuel Transfer Carrier Box."

The "Fuel Transfer Penetration" is included in Table 2.4.1-1, Containment.

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.

Response:

All component and equipment supports are included in LRA Section 2.4.2.6. Because the Intake Structure operating slab is designed to remain functional after a crane load drop, the bridge crane does not have an intended function per 10 CFR 54.4. Cable trenches in the concrete slabs are included in the component type "Concrete in Ambient Air." Conduits embedded in the concrete are included in the concrete analysis (similar to the analysis of concrete reinforcement). Hatches are included in the component type "Structural Steel in Ambient Air." The only missile barrier in the intake structure is the operating floor slab, which is included in the component type "Concrete in Ambient Air."

2.4.2.5 Fuel Handling Equipment and Heavy Load Cranes

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.

Response:

This RAI lists all of the components in Table 2.4.2.5-1 and then focuses on subcomponents that are found in cranes and other lifting devices. It is, therefore, assumed that the RAI is meant to address the aging management of crane subcomponents.

For the cranes that are within scope of license renewal, Table 2.4.2.5-1 identifies the link to AMR Item 3.3.1.15. This AMR Item is in Table 3.3.1 indicating that the aging management of these items is consistent with the GALL Report. In this case, AMR Item 3.3.1.15 is consistent with GALL Report Items VII.B.1-b and VII.B.2-a. It identifies the Overhead Heavy Load and Light Load Handling Systems Program (GALL Report Section XI.M23) and indicates in the Discussion column of the AMR Item that OPPD aging management results are consistent with the GALL Report.

In the FCS LRA, this means that the equipment, the material, the environment, the AERMs, and the AMP are the same as those included in the applicable GALL Report line items. No exceptions have been taken to XI.M23 and, in fact, enhancements have been made to this program to better address the aging of concrete anchors for the equipment included in the program. These enhancements are discussed in Section B.2.6 of Appendix B of the LRA.

Since the aging management of the cranes is consistent with the GALL Report, which does not provide a detailed listing of crane/lifting device subcomponents, OPPD did not deem it necessary to list subcomponents in Table 2.4.2.5-1.

The subcomponents that have been included in scope are the crane/trolley rail systems, hoist monorails, structural members used for the support of the fuel handling equipment, and structural members used for the support of the crane bridge and trolley.

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.

Response:

Per telecon with the NRC, no response is required for the first part of this RAI. A discussion will be provided in the telecon summary to address this issue.

Relative to the boral panels, these have been included in Table 2.4.2.1-1, Auxiliary Building, with the component type "Spent Fuel Storage Racks" and are managed for aging per AMR Item 3.3.1.09.

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.

Response:

Component Supports have been treated as a commodity group. The applicable supports for all of the components that have been included within the scope of license renewal are also within the scope of license renewal and contained within the commodity groupings of Component Supports. They have been grouped by material, environment, general support type, and aging management program. With the exception of stainless steel components in air and structural stainless steel in borated water, which are not addressed in the GALL Report, the aging management of all component supports within scope of license renewal is consistent with the provisions of the GALL Report as indicated in Table 2.4.2.6-1 by the links to AMR Items from the 3.5-1 and 3.5-3 AMR Tables.

The types of supports that are included as component supports are piping hangers; cable conduit, raceway, and supports; tubing supports; HVAC ducting supports; equipment frames and stanchions; frames and saddles for tanks and heat exchangers; equipment metal spring isolators and fixed bases for pumps, fans, air handlers, chillers, air compressors, and EDGs; equipment restraints for the pressurizer and reactor coolant pumps; and electrical equipment anchorage for MCCs, switchgear, distribution panels, and control panels.

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.

Response:

Manhole MH-31 is integral with the Intake Structure. Therefore, the statement "all other portions of manhole MH-31 are evaluated as part of the intake structure (Section 2.4.2.3)" indicates that the concrete structure of MH-31 is included in the Table 2.4.2.3-1 component types "Concrete Below Grade" and "Concrete in Ambient Air."

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.

Response:

The manhole is evaluated with the duct banks. LRA Section 2.4.2.7 specifically states:

> *The boundary for duct banks includes all concrete, carbon steel, gray cast iron, polyurethane foam and elastomer materials that form the electrical manholes and duct banks which* connect *the southeast corner of the Auxiliary Building at Pull Boxes 129T and 128T to the Intake Structure at MH-31. From the pull boxes, the two duct banks combine and connect to manhole MH-5. From manhole MH-5, the duct bank continues to the Intake Structure where it connects at MH-31.*

The pull boxes are included in Table 2.4.2.6-1 component type "Component Support Carbon Structural Steel in Ambient Air" (they are included in the term electrical enclosures in LRA Section 2.4.2.6).

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.

Response:

The exposed conduit and conduit supports associated with MH-31 are included with the Table 2.4.2.6-1 Component Type "Component Support Carbon Structural Steel in Ambient Air."

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).

Response:

The OPPD license renewal documentation has been revised to comply with the NRC Interim Staff Guidance (ISG) related to SBO. OPPD has completed the FCS SBO analysis; that analysis will be reflected in the LRA annual update as well as the update to the USAR Supplement, as appropriate. A copy of the SBO boundary drawing, SBO Figure 8.1-1 (Simplified), has been provided by the Reference 5 letter.

There are no medium voltage cables in the substation switchyard associated with SBO. Medium voltage SBO cables, outside of the substation switchyard, i. e., in the plant, have been addressed as part of the license renewal Cable commodity group and include the cables associated with the 4.16 kV system. Low voltage (typically 120 v) cable is located in troughs and duct banks. High voltage cable is located overhead on towers (single phase). The arrangement of the duct banks is such that they are pitched/sloped at no less than 1/8 " per foot to maintain cable out of long term water immersion by precluding standing water.

The substation (SBO restoration) includes transformers, circuit breakers, disconnect switches (manual and motor operated), high voltage bus work and transmission cables, transmission towers, supports, actuating relays, blocking relays, indicating lights, alarm logic, and miscellaneous electronic components and switches to allow isolation, transformation, and distribution of 345 kV, 161 kV, and 22 kV power to supply the plant 4.16 kV system.

Two offsite startup power sources are available. The dedicated offsite 161 kV system is brought in via two 161 kV/4.16 kV transformers. The 345 kV system can be converted to an offsite power source by opening the motor operated main generator/transformer disconnect switch DS-T1 and back feeding the plant using the main transformer as a step-down transformer to 22 kV power to feed the 22 kV/4.16 kV transformers.

Either offsite power source can operate the four 4.16 kV buses - 1A1, 1A2, 1A3, and 1A4. During normal plant startup the house service buses (1A3 and 1A4) and their associated 480 V systems are normally connected to the 161 kV system and buses 1A1 and 1A2 are normally supplied from the 345 kV/22 kV back feed. During generator synchronization the four 4.16 kV buses are powered from the 161 kV supply.

The SBO Equipment includes transformers, circuit breakers, disconnect switches (manual and motor operated), high voltage bus work, aluminum conductor, steel reinforced (ACSR) transmission cables, insulators associated with the transmission conductors, transmission towers and supports, actuating relays, blocking relays, indicating lights, alarm logic, medium and low voltage cable, connectors, terminal blocks, fuse blocks, and miscellaneous electronic components and switches to allow isolation, transformation, and distribution of 345 kV, 161 kV, and 22 kV power to supply the plant 4.16 kV system.

All electrical components within the Substation SBO Restoration System have been considered and have been evaluated as in the license renewal boundary with the exception of enclosures, panels, terminal blocks, fuse blocks, connectors, and medium and low voltage cables. Enclosures, panels, and power supplies were identified as commodity groups and are reviewed separately. Medium and low voltage cables, terminal blocks, fuse blocks, and connectors are evaluated as a commodity group for the entire plant.

The SBO License Renewal Intended functions are:

- The Substation SBO Restoration System, as configured, provides, transforms, distributes, and isolates 345 kV and 161 kV power to support recovery from station blackout.
- The 22 kV system is the receiver for the 345 kV back feed as an alternate off site power source.
- The SBO Equipment provides an additional source of offsite power by back feeding from the 345 kV system via the main and unit auxiliary transformers, and the isolated phase bus-duct
- The 161 kV substation, 1251, is the normal supply source for safety-related busses 1A3 and 1A4 during all modes of plant operation.

The following are the AMR results tables from Section 9.20 of the EA. These show the programs that have been credited for aging management.

LRA SUMMARY TABLE - 1

Substation - SBO Restoration System Component Types Subject to Aging Effects Review
Results for INTERNAL Environments

Component Type	Material	Internal Environment	AERM	Plant Programs	LRA Table/Line #
22 kV BUS DUCT	Carbon Steel	Dry Air	None	Not Applicable	3.3.2-23
CIRCUIT BREAKER ELECTRICAL ENCLOSURES	Carbon Steel	Outside Air	Loss of Material	Structures Monitoring Program	3.5.1-25

LRA SUMMARY TABLE - 2

Substation - SBO Restoration System Component Types Subject to Aging Effects Review
Results for EXTERNAL Environments

Component Type	Material	External Environment	AERM	Plant Programs	LRA Table/Line #
161 kV DEADEND TOWERS	Galvanized Steel	Outside Air	Loss of Material	Structures Monitoring Program	3.5.1-25
161 kV LINE CARRIER EQUIPMENT	Galvanized Steel	Outside Air	Loss of Material	Structures Monitoring Program	3.5.1-25
22 kV BUS DUCT	Carbon Steel	Outside Air	Loss of Material	Structures Monitoring Program	3.5.1-25
345 kV LINE CARRIER EQUIPMENT	Galvanized Steel	Outside Air	Loss of Material	Structures Monitoring Program	3.5.1-25
BOLTING	Galvanized Steel	Outside Air	Loss of Material	Structures Monitoring Program	3.5.1-25

Component Type	Material	External Environment	AERM	Plant Programs	LRA Table/Line #
CIRCUIT BREAKER ELECTRICAL ENCLOSURES	Carbon Steel	Outside Air	Loss of Material	Structures Monitoring Program	3.5.1-25
CONCRETE PADS AND FOUNDATIONS BELOW GRADE	Concrete	Below Grade	None	Structures Monitoring Program	3.5.1-09
CONCRETE PADS AND FOUNDATIONS IN OUTSIDE AIR	Concrete	Outside Air	None	Structures Monitoring Program	3.5.1-09[2]
GALVANIZED STEEL IN OUTSIDE AIR	Galvanized Steel	Outside Air	Loss of Material	Structures Monitoring Program	3.5.1-25
NON-EQ CABLES Power Application: Misc. 4 kV cable; Insulation types EP, EPDM w/ CSPE Jacket, Misc. 600 volt Application XLPE insulation w/ Neoprene Jacket	Aluminum	Outside Air	None	Non-EQ Cable Program	3.6.1-02
STRUCTURAL STEEL ISOLATED PHASE BUS	Galvanized Steel	Outside Air	Loss of Material	Structures Monitoring Program	3.5.1-25

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)

Response:

(See response to RAI 3.2-1 for a detailed explanation of the OPPD linking process)

Component	Table	Link	Justification
RCP Pump Cover (Thermal Barrier)	2.3.1.2-1	3.2.1.09 (ESF system link) 3.3.2.74 (Auxiliary system link)	3.2.1.09 includes GALL Report Volume 2, Chapter V, Item D.1.5-a, whose Component Description is: D1.5-a D1.5.1 D1.5.2 D1.5.3 D1.5.4 Heat exchangers (reactor coolant pump seal, HPSI pump seal, LPSI pump seal, RHR or SDC) Bonnet/cover Tubing Shell Case/cover OPPD concludes this is an appropriate link since the component, material, environment, AERM and AMP are consistent with NUREG-1801. 3.3.2.74 includes components that interface between the RCS and Component Cooling Water systems. The RCP Pump Cover is such a component. The component list in 3.3.2.74 has been revised to include the RCP Pump Cover.

Component	Table	Link	Justification
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)	The linkages to 3.4.1.02 and 3.4.1.05 have been deleted. Linkage to 3.1.2.06 has been added in place of 3.4.1.05. Linkage to 3.4.1.05 was deleted because the AERM originally identified for this component was determined to be not applicable. Link 3.4.1.06 includes GALL Report Volume 2, Chapter VII, Item F.1-a (See Note 1). OPPD interpreted "Blowdown lines – Piping and fittings" to include the blowdown nozzles. Link 3.4.1.13 includes GALL Report Volume 2, Chapter VIII, Item H.1-a (See Note 2). OPPD interpreted "Blowdown lines – Piping and fittings" to include the blowdown nozzles. An equally appropriate link would have been 3.1.1.27 since GALL Report Volume 2, Chapter IV, Item C2.2-d is included in this item.

Note 1: GALL Volume 2 Chapter 8 Item F.1-a:

F.1-a F.1.1 F.1.2	Blowdown lines Piping and fittings (Group B) Piping and fittings (Group D)	Carbon steel	Secondary side treated water	Wall thinning/ Flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No

Note 2: GALL Volume 2 Chapter 8 Item H.1-a:

H.1-a H.1.1	Carbon steel components (PWRs) External Surfaces	Carbon steel, low-alloy steel	Air, leaking and dripping chemically treated borated water up to 340 deg C (644 deg F)	Loss of material/ Boric acid corrosion of external surfaces	Chapter XI.M10, "Boric Acid Corrosion"	No

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.

(Note RAI typographical error: Information Notice 90-14 referenced instead of 90-04)

Response:

Information Notice (IN) 90-04, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," mainly addressed cracking; however, corrosion and pitting were mentioned:

> *A common factor was the general corrosion pitting on the inside surface of the SGs. Metallography information indicates that the degradation probably results from corrosion-assisted thermal fatigue.*

IN 90-04 noted that these flaws have only been observed in Westinghouse Model 44 and Model 51 vertical, recirculating, U-tube SGs with the feedwater ring design. FCS has Combustion Engineering (CE) steam generators. Based on an evaluation from CE, OPPD concluded that shell-to-cone girth welds at FCS will not be susceptible to cracking.

As Appendix B.2.9 indicates in the clarification bullets, the scope of the Steam Generator Program is expanded to include components in Tables 3.1.1 and Table 3.1.2 for which the Steam Generator Program is identified as an aging management program. See the response to RAI B.2.9-2 regarding the management of these added scope components.

Discussion Item 2 in LRA AMR Item 3.1.1.15 had a typographical error in the Steam Generator Program reference. It has been corrected from "B1.7" to "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 10^{17} n/cm^2 [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.

Response:

The GALL Report identifies this scenario (Item IV.A2.5-b) only for the reactor vessel shell if it is made from SA 508, Class 2 and is exposed to a neutron fluence $>10^{17}$ n/cm^2. The reactor vessel shell components at FCS are fabricated of SA 533, Grade B, Class 1. This scenario does not, therefore, apply to FCS.

Other reactor vessel components that are fabricated of SA 508, Class 2 steel and clad with a stainless steel or nickel-based alloy weld overlay are the reactor vessel flange, the closure head flange, and the primary coolant nozzles, nozzle extensions, and nozzle safe ends. Per a recent Westinghouse analysis performed for FCS, the flanges and nozzles will not experience a fluence of $>10^{17}$ n/cm^2 by the end of the period of extended operation.

Per discussions with Westinghouse/CE, there have been no cases of underclad cracking of any clad CE reactor vessel subcomponents.

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.

Response:

The Alloy 600 components susceptible to PWSCC are identified in the following LRA AMR Items: 3.1.1.09, 3.1.1.11, 3.1.1.15, 3.1.1.24, 3.1.1.25, 3.1.2.09, and 3.1.3.13.

The Alloy 600 Program is a new program at FCS. With this being the case, inspection methodologies for all of the components in the program have not yet been determined. Some of the components that are in the program are currently part of other programs like the Reactor Vessel Internals Inspection Program. The activities that occur under the interfacing programs relative to these components will be utilized to help analyze and determine the methodologies to be incorporated within the Alloy 600 Program for inspection of its included components. These analyses and determinations will be completed prior to entry into the period of extended operation.

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.

Response:

This operating experience was considered in the system evaluation for the IPA. The cracks that were discovered at FCS in 1990 occurred in two unvented, spare CEDM upper housings. The details relative to parts (a), (b), and (c) of the RAI are documented in various previously docketed letters as noted below. Copies of these letters are enclosed.

CEDM cracking at FCS was described in Licensee Event Report 90-28, dated January 14, 1991 (LIC-91-0003L). The cracks were discovered based on the visual observation of boric acid in the vicinity of the cracks while on line that resulted in a forced outage. OPPD determined that the unvented, stagnant conditions in these spare CEDMs were responsible for the cracking and as a result, these conditions were eliminated. Since that time, there has been no further cracking of the CEDM housings at FCS.

Because of industry experience, OPPD in 1999 began a proactive approach to dealing with the CEDM housing cracking phenomenon with the establishment of a CEDM Material Reliability Management Plan to monitor the CEDMs on an outage-by-outage basis through the performance of eddy current testing of the CEDMs. Details of the OPPD approach are contained in a letter from OPPD (R. L. Phelps) to NRC (Document Control Desk), dated January 25, 2002, "Fort Calhoun Station (FCS) Discussion of Control Element Drive Mechanism (CEDM) Housing

Reliability" (LIC-02-0007), and in a letter from OPPD (R. L. Phelps) to NRC (Document Control Desk), dated October 15, 2001, "Fort Calhoun Station (FCS) Control Element Drive Mechanism (CEDM) Housing Reliability Management" (LIC-01-0095).

With respect to item (d) above, activities described in the referenced letters will be continued unless other events or analyses dictate otherwise. OPPD considers this to be a current licensing basis issue, with the resolution incorporated into the appropriate AMPs. OPPD will continue to be involved in industry/regulatory activities relative to this issue and will apply recommended or mandated activities to the maintenance of the FCS CEDM housings as applicable.

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.

Response:

For both the steam generator primary head cladding and the primary side tubesheet, the Steam Generator Program is credited for aging management. See response to RAI B.2.9-2 for aging management of these added scope components.

"Steam Generator Primary Manways (Cladding)," is the next line item in Table 2.3.1.2-1. It references AMR Results Item 3.1.1.33, which credits both Chemistry and the In-Service Inspection Program for the aging management of cracking.

The reactor coolant pump (RCP) thermal barriers are not accessible for routine maintenance or inspection. During the 2001 refueling outage, the "A" RCP rotating assembly was replaced with a new rotating assembly and the existing assembly was sent to a vendor for refurbishment. As part of the refurbishment the thermal barrier on the "A" RCP was visually inspected and a dye-penetrant exam performed. No indications of cracks were identified. A visual inspection was performed on the "C" RCP after it was removed for refurbishment during the 2002 refueling outage. No indication of degradation was identified. OPPD will continue to visually inspect and perform a dye-penetrant exam on the two remaining RCP thermal barriers when the rotating assemblies are refurbished. FCS will credit the One-Time Inspection Program for these RCP thermal barrier inspections.

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.

Response:

The RCP thermal barrier is an integral part of the RCP casing and per the 2nd paragraph of the Program Description of GALL Report Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS), screening for susceptibility to thermal aging is not required for CASS pump casings and valves.

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.

Response:

OPPD has conservatively included Loss of Material as an AERM for Alloy 600 in borated, treated water. This AERM is not identified in the GALL Report for this same material and environment. To validate the effectiveness of the Chemistry program, OPPD will determine the worst-case location for the potential occurrence of this AERM and perform a one-time inspection of this location prior to the period of extended operation.

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?

Response:

OPPD has incorporated an augmented inspection of the thermal shield bolting or pins within the Reactor Vessel Internals Inspection Program. In 1984, a commitment was made to the NRC to perform an inspection of the FCS thermal shield during the 1987 refueling outage. However, in 1986 an inspection deferral program was implemented that allowed a thermal shield monitoring program to replace the inspection commitment (Letter from OPPD (R. L. Andrews) to NRC (A. C. Thadini), dated August 28, 1986, Fort Calhoun Thermal Shield Support System Inspection Deferral (LIC-86-421)). This monitoring program generated data from 1988 through 1990 that indicated the early stages of loosening of the thermal sleeve positioning pins. During the 1992 refueling outage, visual inspection of the support lugs and the positioning pins was performed. The preload of 11 of the 16 lower positioning pins was also performed. Based on the measurements and an analytical evaluation of preload, 7 lower and 4 upper pins were replaced. This action reduced vibrations back to normal levels.

No abnormal vibration has been detected since 1992 and OPPD continues to monitor thermal shield vibrations as a task within the Reactor Vessel Internals Inspection Program (B.2.8).

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)

Response:

The following criteria were used in preparing the linkage between the Section 2 and Section 3 tables in the LRA:

I. As stated in the FCS LRA, OPPD used "engineering judgment" in comparing the FCS aging Management Groups (AMG) to the GALL AMG in preparing the LRA.

FCS aging management review results were classified as being consistent with NUREG-1801 if the comparison between each FCS AMG and a single row from the tables in NUREG-1801, Volume 2 met the following criteria:

1. *The FCS AMG component, material, environment and AERM are determined to be the same, using engineering judgment, as the component, material, environment and AERM documented in NUREG-1801, Volume 2.*

2. *The FCS AMP is determined to be the same, using engineering judgment, as the AMP documented in NUREG-1801, Volume 2; or NUREG-1801, Volume 2 specifies a plant specific AMP.*

OPPD classified an AMG as consistent with the GALL Report if the FCS AMG consisted of the component, material, environment, AERM and AMP as documented in NUREG-1801, Volume 2; therefore, an FCS AMG would be consistent with the GALL Report if the above criteria were met regardless of the system that included the AMG in the GALL Report. Since this information is included in the FCS LRA, OPPD is consistent with the lessons learned from the GALL demonstration project.

Table 1: Observations and Lessons Learned Regarding Application Format

No.	Observations	Lessons Learned
1.3	The appropriate wording to indicate that an applicant's program meets the evaluation as described in the GALL report should be "consistent with." Engineering judgment may be used by the applicants in making this determination. When there is some expectation that NRC staff may not come to the same determination with respect to a particular program element, the applicants should identify these as differences from the GALL report in their license renewal application.	NEI 95-10 and other license renewal guidance documents may need to be updated to provide guidance for the use of the words "consistent with GALL."

Reference: Letter from Christopher I Grimes to Alan P. Nelson, LESSONS LEARNED AND OBSERVATIONS FROM THE LICENSE RENEWAL DEMONSTRATION PROJECT, dated October 3, 2001

II. In assembling links to plant specific programs, OPPD identified the appropriate AMP based on the component, material, environment, and AERM regardless of system.

III. One of the lessons learned from the GALL demonstration project was the need to provide a mechanism to allow the applicant to reference a GALL program for a component not covered by GALL as discussed below.

Table 2: Observations and Lessons Learned During Preparation of Safety Evaluation to Identify Need for Request for Additional Information

No.	Observations	Lessons Learned
2.2	There is a need for the applicant to reference a program evaluated in the GALL report for a component, not covered by the GALL report, if it involves similar intended function, environment, material, aging effect, system, and ASME Code Class (if applicable) with another component.	The license renewal guidance documents need to be updated to allow an applicant to reference a program evaluated in the GALL report for a component not covered by the GALL report if it involves similar intended function, environment, material, aging effect, system, and ASME Code Class (if applicable) with another component. An expectation for allowing this would be that the basis is provided and it is clearly identified and explained in the application.

Reference: Letter from Christopher I Grimes to Alan P. Nelson, LESSONS LEARNED AND OBSERVATIONS FROM THE LICENSE RENEWAL DEMONSTRATION PROJECT, dated October 3, 2001

Since the guidance documents were not updated prior to submittal of the FCS LRA, OPPD referenced the GALL Report for components not covered by GALL if the component involves similar intended function, environment, material, aging effect, system, and ASME Code Class (if applicable) with another component.

Component	Table	Link	Justification
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)	Links 3.3.2.10, 3.3.2.17, and 3.3.2.18 are plant specific programs. Pipes and fittings have been added to the components in 3.3.2.17 and 3.3.2.18.

Component	Table	Link	Justification
Heat Exchanger	2.3.2.2-1	3.3.2.76 (Auxiliary system link) 3.4.1.10 (SPCS link)	Link 3.3.2.76 is for a plant specific program. Link 3.4.1.10 is for the heat exchanger in the Demineralized Water System as discussed on Page 2-43 of the LRA.
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)	Links 3.4.1.02, 3.4.1.05, 3.4.1.06, and 3.4.1.13 are for piping between containment penetrations and containment isolation valves in Auxiliary Systems as discussed on Page 2-43 of the LRA.
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)	Links 3.4.1.02, 3.4.1.05, 3.4.1.06, and 3.4.1.13 are for containment isolation valves in Auxiliary Systems as discussed on Page 2-43 of the LRA.

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.

Response:

This AMR Item is only linked to LRA Table 2.3.2.2-1, Containment Penetrations, and System Interface. The only systems applicable to this discussion column of the LRA are the demineralized water system, instrument air system, and steam generator blowdown system. All containment penetrations associated with other systems were addressed in those respective systems. The "Discussion" column of LRA AMR Item 3.2.1.04 should read, "No FCS containment isolation valves and associated piping in systems that are addressed in this section

of the application were determined to be subject to the aging effect of loss of material due to microbiologically influenced corrosion." The operating experience at Fort Calhoun is such that MIC has not been experienced in any of these FCS systems.

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.

Response:

Per telecon with the NRC, no response is required for this RAI. A discussion will be provided in the telecon summary to address this issue.

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.

Response:

These component terms are not used interchangeably since they are two separate and distinct components. They have been identified separately in Table 2.3.2.1-1 of the LRA specifically to prevent such confusion. Referring to this table, the SI leakage cooler accumulators are addressed under the Component Type "Leakage Accumulators." The safety injection tanks are addressed under the Component Type "Injection Tanks."

The SI leakage cooler accumulators, SI-7A, -7B, -7C, and -7D, are carbon steel vessels internally clad with stainless steel. SI-7A and -7B are located in zones A5 and A8, respectively, on drawing E-23866-210-130, Sheet 2. SI-7C and -7D are located in zones A8 and A5, respectively, on drawing E-23866-210-130, Sheet 2B.

The safety injection tanks, SI-6A, -6B, -6C, and -6D, are entirely stainless steel vessels. SI-6A and -6B are located in zones C/D3 and C/D6, respectively, on Drawing E-23866-210-130, Sheet

2. SI-6C and -6D are located in zones C/D6 and C/D3, respectively, on drawing E-23866-210-130, Sheet 2B.

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.

Response:

LRA AMR Item 3.2.3.02 applies to the stainless steel liner of the SI leakage cooler accumulators, as indicated in the "FCS Material" column of that entry. Refer to Table 2.3.2.1-1 of the LRA. For the "Leakage Accumulator" Component Type in that table, the reader is provided with links to LRA AMR Item 3.2.3.02, for the accumulator internals, and to LRA AMR Item 3.2.1.11 for the accumulator externals. For the "Injection Tank" Component Type, the reader is provided links to LRA AMR Items 3.2.2.04 and 3.2.3.01.

3.3 Auxiliary Systems

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.

Response:

In the FCS LRA, the environments used in the Section 3 AMR tables match those that are used in the GALL Report. In all of the 3.X-1 tables, each line item corresponds exactly with a GALL Report line item. The same is true for the 3.X-3 tables. Where there is a differentiation relative to the temperature, oxygen content, use of a corrosion inhibitor, etc. within an environment specified in the GALL Report (e.g., high temperature borated treated water, deoxygenated

treated water >200 deg F, oxygenated treated water <200 deg F, etc.), the same differentiation has been used in the FCS LRA.

For ambient air at FCS, to simplify the IPA and review processes, there was no differentiation made between indoor air, outdoor air, or containment air relative to applicable AERMs. All applicable AERMs that could apply for worse case ambient air conditions were assumed wherever a material was subjected to an ambient air environment. The use of descriptors such as plant indoor air, outdoor air, ambient air, containment air, etc. were used to address locale only and had nothing to do with the determination of AERMs.

The only exception to the discussion in the previous paragraph is where a component in ambient air could be subjected to local borated water leakage. Then, of course, AERMs associated with exposure to borated water would apply.

The following tables provide internal and external environment information for within scope of LR systems at FCS.

Internal Environments for Systems Within Scope of LR

Environment	Description
Dry Air/Gas	Instrument Air, Nitrogen, Diesel Starting Air, Hydrogen, Halon, Refrigerant
Ambient Air	Compressed Air, Gaseous Waste, Diesel Exhaust, Building Air, Outside Air
High Temperature/ Neutron Fluence/ Borated Treated Water	Reactor Vessel, Reactor Vessel Internals
Borated, Treated Water	Reactor Coolant, Safety Injection, Containment Spray, Spent Fuel Pool Cooling, Liquid Waste, Primary Sampling, CVCS
Saturated Steam	Main Steam, Turbine Extraction Steam
Deoxygenated, Treated Water	>200 deg F – Feedwater, Auxiliary Feedwater, SG Blowdown <200 deg F – Auxiliary Feedwater
Glycol Corrosion-Inhibited, Treated Water	EDG Jacket Water
Nitrite Corrosion-Inhibited, Treated Water	Closed Cycle Cooling Water
Oxygenated, Treated Water	Demineralized Water, Fire Protection

Environment	Description
Raw Water (Missouri River water)	Raw Water, Fire Protection, Liquid Waste
Fuel Oil	Emergency Diesel Fuel Oil, Auxiliary Boiler Fuel Oil, Diesel Fire Protection Pump Fuel Oil
Lubricating Oil	Emergency Diesel Lubricating Oil, RCP Lubricating Oil, Auxiliary Steam Turbine Lubricating Oil
Liquid Halon	Fire Protection
Liquid Refrigerant	Control Room Ventilation, Primary Sampling

External Environments for Systems Within Scope of LR

Environment	Description
Auxiliary Building	Winter: 70 deg F. Summer: 105 deg F. 20% – 100% relative humidity
Turbine Building	Winter: 65 deg F. Summer: 105 deg F. 20% – 100% relative humidity
Control Room	Winter: 72 deg F. Summer: 78 deg F. 50% relative humidity
Containment	Winter: 55 deg F. Summer: 120 deg F. 20% – 100% relative humidity
Outdoors	Winter: -11 deg F. Summer: 95 deg F, 78 deg F Wet Bulb

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.

Response:

The aging effects of hardening and loss of strength for elastomers are not included in the General Corrosion of External Surfaces Program (B.3.3). Enhancements will be made to add these AERMs to preventive maintenance tasks under the Periodic Surveillance and Preventive Maintenance Program (PS/PMP)(B.2.7) to specifically perform hands on type inspections of elastomer expansion joints, seals, and vibration isolators within the scope of license renewal for hardening and loss of strength. Applicable PMs are performed at least once per refueling cycle (approximately 18 months). The PS/PMP has been added to Discussion Item 2 in AMR Item 3.3.1.02.

Relative to monitoring for cracks and loss of material, procedural guidance requires system engineers to perform walkdowns of their assigned systems on a quarterly basis, as a minimum. Operator walkdowns occur multiple times per 12-hour shift. No instances of the loss of ventilation system intended function due to failure of elastomers have been found in existing corrective action documentation.

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.

Response:

The Instrument Air System boundary does not include components upstream of the dryers. Those components are part of the Compressed Air System. The industry operating experience is varied because of the differences in system design and air dryer types in use. For stations with refrigerant dryers, the dewpoint of the air system is typically in the range of +30 deg F to +40 deg F. While this does prevent water accumulation in the system, it still provides sufficient moisture to allow corrosion. Also, for systems with a single air dryer, wet air can be pumped into the system in the event of a failure of the air dryer. Additionally, if the system dewpoint is not monitored, that condition can go undetected for a significant length of time, which can cause corrosion to occur.

The Fort Calhoun operating experience has not shown that a wet environment exists downstream of the air dryers. The reasons for that are threefold. First, Fort Calhoun has always used desiccant type air dryers which, reduce the dewpoint of the instrument air to <-40 deg F. This low level of moisture has been shown to preclude the corrosion mechanisms responsible for loss of material that occur in wet systems. Second, Fort Calhoun has redundant air dryers installed. Lastly, the dewpoint of the instrument air is monitored with a sensor which alarms in the control room in the event the dewpoint exceeds -25 deg F. No significant corrosion occurs on iron, zinc, copper, aluminum or their alloys at relative humidities below 60% (Ref. "Corrosion Volume 2," 2nd Edition, by L.L. Shreir, PHD, FRIC, FIM, FICorrT, FIMF Head of Department of Metallurgy and Materials, City of London Polytechnic.) The relative humidity of the instrument air at a dewpoint of -25 degrees is less than 2%.

The operating experience review for Fort Calhoun Station did identify a single water intrusion event that introduced water into the Instrument Air System from the Fire Protection System due to a crosstie between the two systems downstream of the air dryers. This was a one time event (Ref. LER 87-025) of short duration, however, and not the normal operating environment. The crosstie was eliminated and the Instrument Air System was cleaned and dried following that event. Since the modification there has been no incidence of high moisture in the IA System.

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.

Response:

There is no link to AMR Item 3.3.1.03 in Table 2.4.2.5-1 of the LRA as stated in the RAI. It does not apply to the load handling system.

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.

Response:

Reference to Table 3.3.1 was inadvertently omitted from the description statement for AMP B.3.5. Performance of a one-time inspection on RCP oil collection system components within the scope of license renewal is currently included as a requirement in the FCS One-Time Inspection Program.

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.

Response:

The FCS scoping and screening process categorized the spent fuel storage racks as structural function components in the "Auxiliary Building" which is listed in AMP B.2.7 as a system/structure within the scope of the Periodic Surveillance and Preventive Maintenance Program. The program currently includes aging management activities to monitor the spent fuel storage racks for loss of material and reduction of neutron absorbing capacity.

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.

Response:

The Bolting Integrity Program applies to bolting in high-energy systems. The programs that have been credited for aging management of bolting in the low and moderate energy systems are generally selected because of procedural activities within those programs that inspect bolting during the disassembly of system components for maintenance, etc.

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.

Response:

The flexible hose pressure boundary is carbon steel pipe, with a gasketed carbon steel coupling at each end, allowing for the flexibility of the connection.

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.

Response:

There are locations in the Auxiliary Building where fire hose cabinets are in proximity to a system containing boric acid; therefore, AMR Item 3.3.1.13 was credited for managing aging effects on these cabinets.

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.

Response:

Fire pumps FP-1A and FP-1B are wet pit, vertical turbine pumps and, as such, the external environment is also raw water. LRA AMR Item 3.3.1.20 also applies to the external environment of the fire pump casings, which also require 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.

Response:

The pump casings listed in LRA Table 2.3.3.16-1 are, in fact, cast iron, which is susceptible to selective leaching. LRA AMR Item 3.3.1.24 identifies selective leaching for both Open-Cycle Cooling Water systems and Closed-Cycle Cooling Waters Systems. GALL Report Volume 2, Chapter VII, Sections C1.1-c and C2.3-a are both included in AMR Item 3.3.1.24. The component cooling water pump casings correlate to Item VII.C2-3-a of the GALL Report.

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.

Response:

The internal environment of the liquid waste disposal system is either borated treated water in the containment or raw (fire protection) water in the auxiliary building. LRA Table 2.3.3.17-1 is linked to LRA AMR Item 3.3.2.96, which applies to stainless steel in a borated treated water internal environment. An additional link to LRA AMR Item 3.3.1.16 has been added to LRA Table 2.3.3.17-1 component types "Pipes & Fittings" and "Valve Bodies" to address the internal environment of raw (fire protection) water in carbon steel and stainless steel components. Additionally, component type "Pumps" has been deleted from LRA Table 2.3.3.17-1, as they are not required for the liquid waste disposal system to perform its intended license renewal function of firewater removal.

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.

Response:

OPPD has concluded that if through-wall perforation of any Liquid Waste Disposal System pipe or fitting imbedded in concrete occurs, there will still be a clear channel for drainage of any fire suppression water from the area of concern down to the sump. There are, therefore, no AERMs for these components at FCS.

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.

(NOTE: RAI Correction – revise LRA Table number to 2.3.3.18-1.)

Response:

Only the gaseous waste disposal compressor seal water heat exchangers with an environment of "oxygenated treated water up to 200 degrees" are in scope for license renewal. Please refer to drawing 11405-M-98, Sh. 1 as revised for RAI 2.3.3.16-6. The associated seal water piping is not in scope for license renewal; therefore, the environment of "oxygenated treated water up to 200 degrees" only pertains to the external side of the stainless steel tubes. They are in scope because they provide a pressure boundary for the CCW System.

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.

Response:

The link to LRA AMR Item 3.3.1.08 has been deleted. Given the material/environment/AERM combination, the more appropriate links for these components are to GALL Report Items V.A1-a and V.A4-a. These GALL Report Items are represented by LRA AMR Item 3.3.3.01. The links to AMR Item 3.3.1.08 have been removed from Table 2.3.3.1-1 for all components other than the Heat Exchangers and replaced with AMR Item 3.3.3.01. Refer to RAI 3.3-1.

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.

Response:

CVCS Heat Exchangers are linked to LRA AMR Item 3.3.1.05 because the Letdown Heat Exchanger has a carbon steel shell subject to external corrosion.

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.

Response:

There is only one link in the LRA to AMR Item 3.3.2.77 and this link was made in error. Refer to the Filters/Strainers entry in Table 2.3.3.15-1 of the LRA. In the Aging Management Review Results column, a link is provided to AMR Items 3.3.2.77 and 3.3.1.16. The correct link for the aging management of the Filter/Strainer housing internals is 3.3.1.16. The link to AMR Item 3.3.2.77 has been removed from Table 2.3.3.15-1 and AMR Item 3.3.2.77 has been revised to read "Not used in application."

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.

Response:

SCC of stainless steel requires a sustained, wetted, high-temperature, chloride environment and bolting stress (see response to RAI 3.2.1-2). Borated water leakage onto stainless steel bolting, should it occur, does not provide the sustained environment necessary for the mechanism. The high temperature required is not present on external bolting.

Additionally, the Bolting Integrity Program is credited for the aging management of bolting in CVCS. In Table 2.3.3.1-1, Chemical and Volume Control System, there is a link to AMR Item 3.3.1.23, which credits the Bolting Integrity Program.

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.

Response:

As denoted in the clarifications to AMP B.2.3, the Diesel Fuel Monitoring and Storage Program also employs leak detection for the Fire Protection Diesel Fuel Oil tank. Leak detection includes external aging. AMR Items 3.3.2.44, 3.3.2.21, and 3.3.2.47 relate to piping/tubing attached to the Fire Protection Diesel Fuel Oil Tank which is above ground, surrounded by gravel, and enclosed in a concrete structure. If this buried piping leaked, it would leak into the enclosure. The second bullet to AMP B.2.3 has added "and buried piping" in addition to the tank, as the

leak detection mechanism includes detection of the buried piping attached to this tank. See response to RAI B.2.3-1 for reasons that leak detection is adequate to maintain the system design requirements.

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.

Response:

Fouling has not been identified as an AERM because the cooling medium for these coolers is Closed Cycle Cooling Water (CCW). For these Containment HVAC coils, FCS operating experience has shown that fouling does not occur. Consistent with the GALL Report, fouling is only applicable as an AERM for heat exchangers when an Open Cycle Cooling Water System is used. The only open-cycle cooling water heat exchangers at FCS are the CCW/RW heat exchangers. Visual inspections for fouling of the CCW/RW heat exchangers is currently performed every 18 months, and heat transfer performance performed every six months.

Regarding the staff's request for clarification on the exception noted in FCS' Cooling Water Corrosion Program (B.2.2), the exception taken is for fluid flow and not heat transfer function. Heat transfer performance testing on applicable heat exchangers is performed per OPPD's response to GL 89-13.

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.

Response:

See the response to RAI 3.3.2-4.

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.

Response:

The buried pipe contains stagnant raw water; therefore, the only aging effects applicable are change in material properties due to leaching of calcium hydroxide (only occurs in flowing water), and change in material properties/loss of material due to aggressive chemical attack (only occurs in aggressive water).

There is no flowing water around or within the pipe; therefore, change in material properties due to leaching of calcium hydroxide is not an applicable aging effect. The groundwater and the river water (raw water) at FCS has been tested and found to be benign (sulfates < 1,500 ppm, chlorides < 500 ppm, and pH > 5.5); therefore, change in material properties/loss of material due to aggressive chemical attack is not an applicable aging effect.

Plant operating experience has shown no age-related degradation of this pipe. A recent modification (valve replacement) required excavation in the vicinity of the concrete pipe. This provided an opportunity for inspection. The exterior and interior surfaces of the pipe showed no signs of degradation.

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.

Response:

These items were included with the Auxiliary Systems because fuel storage and its included components are contained in GALL Report Volume 2, Chapter VII, Auxiliary Systems.

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.

Response:

The filters/strainers in question are bronze in a lubricating oil environment, are subject to loss of material, and are managed for aging with the Periodic Surveillance and Preventive Maintenance Program. "Filters/Strainers" has been added to the "Component Types" column in AMR Item 3.3.2.85.

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.

Response:

AMR Item 3.3.2.21 is not a link for "Tanks" in LRA Table 2.3.3.4-1; however, it is for "Tanks" in LRA Table 2.3.3.5-1. "Tanks" has been added to the "Component Types" column in 3.3.2.21.

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.

Response:

The link to AMR Item 3.3.2.76 in the "Valve Bodies" Component Type within LRA Table 2.3.3.15-1 applies to the valves associated with the seal water for the Raw Water Pumps. "Valve Bodies" has been added to AMR Item 3.3.2.76.

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.

Response:

The normal environment for these components is ambient air. It is possible, although improbable, that there can be leakage of water from borated water systems onto exposed carbon steel surfaces. For this reason, that possibility is covered by providing the link through AMR Item 3.3.3.09 to AMR Item 3.3.1.13, which corresponds to GALL Report Item VII.I.1-a. In addition, Table 3.3-3, Row Number 3.3.3.09 has been revised to read "Loss of Material due to boric acid corrosion" in the FCS AERMs column to correctly match AMR Item 3.3.1.13.

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.

(NOTE: There is a typographical error in the RAI. The GALL Report Item referenced in 3.4.1.02 is VIII.G.4-b, not VII.G.4-b.)

Response:

The only table in which a link to LRA AMR Item 3.3.3.03 is made is Table 2.3.3.1-1 (Chemical and Volume Control System) for the Component Types "Pipes and Fittings" and "Valve Bodies." For these components that link to AMR Item 3.3.3.03, the Chemistry Program and the One Time Inspection Program are credited for aging management. The One Time Inspection Program has been added to the "FCS Program Activity" column for Item 3.3.3.03.

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.

Response:

As with the previous RAI, the only table in which a link to LRA AMR Item 3.3.3.04 is made is Table 2.3.3.1-1 (Chemical and Volume Control System) for the Component Types "Pipes and Fittings" and "Valve Bodies." This was determined to be an incorrect link.

The more appropriate links for these components, given the material/environment/AERM combinations, are to GALL Report Items V.A1-a and V.A4-a for piping and fittings and for valves, respectively. These GALL Report Items are equivalent to LRA AMR Item 3.3.3.01. AMR Item 3.3.3.04 has been removed from Table 2.3.3.1-1 and replaced with AMR Item 3.3.3.01. Refer to RAI 3.3-1. Additionally, AMR Item 3.3.3.04 has been changed to read "Not used in application."

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 °C and for flow orifice bodies in treated water with water temperature less than 35 °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.

Response:

The "FCS Components" column of 3.3.3.08 should read "Electric Heaters" instead of "Electric Heater Sleeves." These components are essentially small tanks with immersion heaters built into the tanks (the tanks are actually entitled "Immersion Heater" on the two Diesel Generator Jacket Water (DGJW) boundary drawings) to prevent the water in this system from freezing when the diesels are not running. The "FCS Components" column of AMR Item 3.3.3.08 has been revised to read "Electric Heaters."

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.

Response:

On an individual component basis, LRA AMR Item 3.3.1.05 actually credits the Periodic Surveillance and Preventive Maintenance Program or the General Corrosion of External Surfaces Program or the Fire Protection Program. For any single component, only one of these programs is credited. The context of the discussion in the "Discussion" column of AMR Item 3.3.1.05 (and all other similar AMR Items where multiple programs are listed) is that there are three programs used for aging management of components that are linked to the AMR Item. It does not mean that all three programs are used or that some combination of two programs is used for aging management of single components.

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.

   Response:

   As a result of corrections to the LRA tables, AMR Item 3.3.3.01 has been revised. See the response to RAI 3.3-1.

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.

Response:

See the response to 3.3.3-2.

LRA AMR Item 3.4.1.02 has been revised. In the "Discussion" column, Item 2 has been revised to read "Consistent with NUREG-1801, this group includes carbon steel and stainless steel in treated water at FCS." The omission of stainless steel was an oversight.

In the "Aging Effect/Mechanism" column of AMR Item 3.4.1.02, the reference to general corrosion has a parenthetical clarification that it applies to carbon steel only. Pitting and crevice corrosion applies to both carbon steel and stainless steel. AMR Item 3.4.1.02 has been utilized to represent GALL Report Items VIII.D1.1-c, VIII.D1.2-b, VIII.G.1-c, VIII.G.2-a, VIII.G.3-a (all of which represent carbon steel components), and VIII.G.4-b (which represents stainless steel components). They all share the same environment of deoxygenated, treated water <200 deg F and the same AERMs (with the noted clarification between carbon steel and stainless steel), and they all recommend AMPs of Chemistry and One Time Inspection.

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.

Response:

The reason that AMR Item 3.3.3.09 was created was because the GALL Report Items that correspond to AMR Item 3.3.1.13 address only carbon and low alloy steel. Boric acid corrosion is also applicable to cast iron, cadmium plated steel, galvanized steel, and copper alloy components that are subjected to the same potential borated water system leakage. These components are also to be managed by the Boric Acid Corrosion Prevention Program; therefore, AMR Items 3.3.3.09 and 3.3.1.13 are virtually the same. They have the same material/environment/AERM/AMP combination where the material is "metals subject to boric acid corrosion."

3.4 Steam and Power Conversion Systems

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.

Response:

Cracking is already identified and managed as an AERM for applicable components in the Steam and Power Conversion Systems. Mechanical vibration is a mechanism that can result in cracking. At FCS, mechanical vibration is not considered to be an aging issue. It is a design issue. When it occurs, it typically involves the misapplication of mechanical components, the improper sizing of components or piping, the improper location of piping fittings that change flow direction, or some combination of these. As such, cases of mechanical vibration problems, especially where damage has occurred, are eliminated via design changes.

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.

Response:

Per telecon with the NRC, no response is required for this RAI. This will be documented in a telecom summary. See the response to RAI 3.3-2.

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.

Response:

These heat exchangers are the lube oil coolers for the steam driven Auxiliary Feedwater Pump. The cooling medium is neither Open nor Closed Cycle Cooling Water. It is auxiliary feedwater

off of the discharge of the pump. There is no GALL Report line item equivalent to this component. Given the copper alloy material and the environments of deoxygenated, treated water and lube oil, the programs selected for the aging management of these coolers (One Time Inspection (B.3.5), Selective Leaching (B.3.6), and Periodic Surveillance and Preventive Maintenance (B.2.7)) have been deemed to be appropriate and provide aging management functionality that is equivalent to the GALL Report for cooling water programs.

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.

Response:

Worst-case locations will be evaluated and identified, taking into account severity of condition, time of service, and lowest design margin, as part of the implementation of the One-Time Inspection Program (B.3.5) prior to the period of extended operation.

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.

Response:

The applicable flow element/orifice housings at FCS are stainless steel. Refer to Steam and Power Conversion Section Table 2.3.4.2-1, Auxiliary Feedwater, to see that the component type "Flow Element/Orifice Housings" is included. From the AMR Item links of 3.4.2.08, 3.4.2.09, and 3.4.2.02, it is seen that these components are fabricated of stainless steel; therefore, FAC does not apply.

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.

Response:

Refer to Section 4.3.4 of the LRA for discussion relative to the fatigue considerations of Class II and III piping. The design code operational limits for this piping, is based on 7000 cycles, is being treated as a TLAA, and is included within the scope of the Fatigue Monitoring Program (B.2.4). Since the Auxiliary Feedwater system is fed from a storage tank inside the Auxiliary Building, the only portions of the AFW system which actually sees thermal fatigue cycles are the nozzles and a short section of piping off the Steam Generators.

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.

Response:

There are no known analytical tools that can accurately model and predict the corrosion rates in strainer or valve bodies. The FAC Program uses the corrosion rates on the downstream piping as a qualitative indicator of the corrosion rates in the strainer or valve bodies to determine inspection and verification requirements for the valve or strainer body in this case. This is a conservative approach since the bodies of the components are much thicker than the piping. Additionally the ability to ultrasonically test valve bodies or strainer bodies is very limited so any components that are identified as having a high corrosion rate will be disassembled and visually inspected.

3.5 Structures

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?"

Response:

The Nuclear Detector Cooling System is used to cool the air in the annulus between the reactor vessel and the biological shield. While the nuclear detectors can withstand temperatures considerably higher than 150 deg F, the elevated temperature could result in reduction in concrete strength through loss of moisture. Each nuclear detector well cooling unit is rated at 100% of the system design capability of 173,000 Btu/hr. A test was performed during Hot Functional and/or Low Power Tests to determine (1) the correlation between annulus air temperature and concrete temperature, and (2) the rate at which the concrete will heat up if no cooling is available. The results of these tests were used to provide control room indication of concrete temperatures (that is annulus air temperature) and allowable reactor operation time in the event both nuclear detector well cooling units were inoperable. The objective for this specification is to hold the concrete bulk temperature to no greater than 150 deg F. Temperature sensors are installed in the concrete and in the annulus air discharge. The sensors in the concrete are subjected to neutron flux during operation and are no longer functional. The indicated values for annulus exit temperatures which correlate with concrete temperatures were determined, including a maximum value used to comply with the Tech Spec limit. A reanalysis was performed in 1987 to verify the original data obtained in 1973. The correlation between the annulus air temperature, concrete temperature of 150 deg F, and the Alarm Temperature setpoint is shown below for the analysis done in 1987. The alarm temperature setpoints correspond to the Technical Specification Limiting Condition for Operation.

Instrument	Air Temperature for 150 deg F Concrete	Alarm Temperature Deg F
732A	145.2	143.2
733A	153.1	151.1
733B	153.1	151.1
734A	172.2	170.2
735A	175.2	173.2
736A	163.0	161.0

Instrument	Air Temperature for 150 deg F Concrete	Alarm Temperature Deg F
736B	172.8	170.8

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.

Response:

This question appears to take the information in the Discussion column of LRA AMR Item 3.5.1.10 out of context. Because the information in the Discussion column of that line item is relative to the adverse effects to concrete from elevated temperature only, the quoted statement is relative to elevated temperature degradation only. In Table 2.4.1-1 of the LRA, notice that for every component type that includes concrete, there are multiple links to LRA AMR Items. Each of these links addresses a particular AERM(s) relative to concrete that corresponds to a matching GALL Report line item. The Discussion column in each of the LRA AMR Items identifies why OPPD has determined that the applicable AERM(s) in its corresponding GALL Report line item is not applicable to FCS; however, it also identifies that OPPD is crediting the GALL Report recommended AMP for the aging management of the structure anyway. As stated in the response to RAI 3.5.1-2 , this RAI question appears to be invalid since OPPD is consistent with the GALL Report with the application of the recommended programs. Further information on

the operating experience of Containment inspections is provided in the following paragraph, however.

In the case of the FCS Containment, per the LRA AMR Items referenced in Table 2.4.1-1 for the concrete component types, inspections are performed of their component parts under both the Structures Monitoring Program and the Containment ISI Program, described in LRA Appendix B Sections B.2.10 and B.1.3, respectively. The containment inspection surveillance test is performed at a frequency of every other refueling outage based on requirements contained in Section 3.5 of the FCS Technical Specifications.

Containment inspections have been performed in 1996, 1999, and 2002 with no evidence of significant structural degradation identified on the biological shield walls and support areas of reactor coolant pumps and steam generators. Inspections of the support area of the reactor vessel are not performed due to inaccessibility and inability to visually inspect the support area from the containment sump.

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?

Response:

Ground water and river water samples were taken in June 2000 and evaluation results were compared to samples taken during plant construction. No significant deviation in sample results was identified. A periodic task will be initiated as part of the Structures Monitoring Program (B.2.10) to take ground water samples on a five year frequency and compare the evaluation results to previous samples.

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.

Response:

Cracking due to cyclic loading of these bellows will be managed, per LRA AMR Item 3.5.1.02 (based on GALL Report Items II.A3.1-c and -d), by the Containment ISI (B.1.3) and Leak Rate (B.1.4) Programs which are consistent with programs XI.S1 and XI.S4 outlined in the GALL Report (i.e., the visual examination categories identified in the RAI are included in the credited programs).

Relative to SCC, however, GALL Report Item II.A3.1-d identifies that "In the case of bellows assemblies, SCC may cause aging effects particularly if the material is not shielded from a corrosive environment." For stainless steel, the corrosive environment needed for SCC to occur is a high-temperature, wetted, chloride environment (see response to RAI 3.2.1-2). At FCS, the bellows are normally in an air environment. There are no bolted connections near these bellows assemblies that could result in leakage that would provide the necessary environmental conditions. LRA AMR Item 3.5.1.02 Discussion column, Item 4 is based on these operating parameter assumptions.

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.

Response:

Review of historical and recent maintenance and corrective action documents did not identify any anomalies which could lead to significant corrosion of the inaccessible areas of the FCS containment liner plates. The most recent inspection of the containment liner and moisture barrier was performed in April 2001 to satisfy ASME Section XI IWE requirements. The inspection identified some areas of corrosion on the liner near the moisture barrier and some separation and trenching of the moisture barrier. Repairs were made to the moisture barrier during the 2002 refueling outage. This included removal of the top portion of the moisture barrier to inspect inaccessible sections of the liner. Only minor surface corrosion was found on the liner extending only 1/8" to 1/4" below the top of the existing joint sealer. Repairs were performed to recoat the liner and restore the moisture barrier. Containment inspections

performed under the FCS Containment Inservice Inspection Program and Structures Monitoring Program will ensure the integrity of the liner is maintained. Additional information on the liner inspection results is included in the response to RAI B.1.3-1.

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.

Response:

These stainless steel threaded fasteners are for the fuel transfer tube blind flange (containment side). The blind flange is removed prior to filling the refueling canal; therefore, the fasteners are not subject to an environment that would support aging effects.

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.

Response:

Refer to the response to RAI 3.1-2. For concrete at FCS, even though OPPD has concluded that the AERMs identified for concrete in the GALL Report are not applicable due to the plant's operating experience, OPPD has committed to be consistent with the GALL Report and monitor for the possibility of the AERMs with the programs identified in the GALL Report.

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.

Response:

See the response to RAI 3.5.1-13.

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.

Response:

See the response to RAI 3.5.1-13.

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.

Response:

See the response to RAI 3.5.1-13.

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.

Response:

AMR Item 3.5.1.28 is consistent with GALL Report line item III.B1.1.3-a. That line item specifies its applicability to both steel and non-steel components and parenthetically includes lubrite plates. It addresses the same AERMs and specifies the same AMP. Item 2 in the Discussion column of AMR Item 3.5.1.28 will be revised to read as follows: "Consistent with NUREG-1801, this group includes steel and non-steel components (including lubrite plates) exposed to ambient air at FCS."

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.

Response:

See the response to RAI 3.5.1-8.

The Missouri River water was tested periodically from 1973 to 1981. The results showed a pH average of 8.16, chlorides of 12.7 ppm, and sulfates of 200.6 ppm (USAR Section 2.7.1.4 in Table 2.7-3). River water test results from samples taken annually between 1990 and 1999 showed a pH average of 8.24.

The groundwater was tested in August 1966 and the average results showed a pH of 7.3, chloride content of 34 ppm, and sulfate content of 162 ppm (USAR Section 2.7.2.3 in Table 2.7-4).

To verify the river water and groundwater chemistry had not significantly changed over 20-30 years, a chemical analysis was performed in June 2000. Those test results indicated groundwater pH was 7.48, chlorides were 8.0 ppm, and sulfates were 79.0 ppm; river water pH was 8.39, chlorides were 14.0 ppm, and sulfates were 229 ppm.

NUREG-1557 indicates aggressive environments for concrete have a pH less than 5.5, sulfates greater than 1500 ppm, and chlorides greater than 500 ppm.

3.6 Electrical and Instrumentation and Controls

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.

Response:

See the responses to RAIs 2.5-1 and B.3.4-1

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.

Response:

As a general comment, 10 CFR 54.21(c)(1) does not require that TLAA related analyses be submitted with the LRA as long as they are completed, reviewed, and approved by the NRC prior to the PEO. Refer to 10 CFR 54.29(a), "Actions have been identified and have been or will be taken." At the time of the application, revised pressure-temperature and LTOP limits were under review. This review has been completed and the NRC has approved the revised limits and issued Technical Specification Amendment 207 for Fort Calhoun Station. The current curves are good for 40 EFPY. Using the methodology approved with the issuance of Technical Specification Amendment 207, OPPD has projected the pressure-temperature and LTOP limits to the end of the period of extended operation and determined that the reactor pressure vessel can be operated 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

Response:

a)

Plate/Weld Number	Plate/Weld Heat No.	Fluence at 1/4T ($n/cm^2 \times 10^{19}$)
D 4802-1	C 2585-3	2.28

D 4802-2	A 1768-1	2.28
D 4802-3	A 1768-2	2.28
D 4812-1	C 3213-2	2.28
D 4812-2	C 3143-2	2.28
D 4812-3	03143-3	2.28
2-410	51989	1.62
3-410	13253	1.62
3-410	27204	1.62
3-410	13253/12008	1.62
3-410	12008/27204	1.62
9-410	20291	2.28

b) Position 2.2 of RG 1.99, Revision 2, was used in determining the decrease in Charpy USE for each beltline material.

c)

PLATE #	HEAT #	Cu CONTENT (%)	INITIAL USE (FT-LB)
D 4802-1	C 2585-3	0.12	75.4
D 4802-2	A 1768-1	0.10	120
D 4802-3	A 1768-2	0.11	77.4
D 4812-1	C 3213-2	0.12	88.5
D 4812-2	C 3143-2	0.10	87
D 4812-3	C 3143-3	0.10	89.7

Weld Number	Wire Heat Number	Initial USE (ft-lb.)	Flux Type	Flux Lot No.	Cu Content (%)
2-410	51989	84	Linde 124	3687	0.170
3-410	12008 and 13253 (Tandem)	97	Linde 1092	3774	0.210

Weld Number	Wire Heat Number	Initial USE (ft-lb.)	Flux Type	Flux Lot No.	Cu Content (%)
3-410	27204 (Tandem)	94	Linde 1092	3774	0.203
3-410	13253 (Tandem)	110	Linde 1092	3774	0.221
3-410	12008 and 27204 (Tandem)	97.8	Linde 1092	3774	0.219
9-410	20291	105	Linde 1092	3833	0.216

d) See response to item c). References for surveillance data are included in (1) Letter from OPPD (W. G. Gates) to USNRC (Document Control Desk), Dated July 6,1992. (LIC 92-203R) "Response to NRC Generic Letter (GL) 92-01, Revision 1: Reactor Vessel Structural Integrity," and (2) CEOG Report CEN-636, Revision 2, Evaluation of Reactor Vessel Surveillance Data Pertinent to the Fort Calhoun Reactor Vessel Beltline Materials, Westinghouse Electric CE Nuclear Power, Final Report dated July 19, 2000.

e)

Plate/Weld Number	Plate/Weld Heat No.	Fluence at 1/4 t (n/cm^2)	Cu (%)	Initial USE (ft-lb.)	Position 2.2 Capsule Modified % USE Decrease	Predicted Irradiated USE from Position 2.2(ft-lb.)
D 4802-1	C 2585-3	2.28×10^{19}	0.120	75.4	33.5	50.1
D 4802-2	A 1768-1	2.28×10^{19}	0.100	120	30.8	83.0
D 4802-3	A 1768-2	2.28×10^{19}	0.110	77.4	32.2	52.5
D 4812-1	C 3213-2	2.28×10^{19}	0.120	86.5	33.5	57.5
D 4812-2	C 3143-2	2.28×10^{19}	0.100	87	30.8	60.2
D 4812-3	C 3143-3	2.28×10^{19}	0.100	89.7	30.8	62.1
2-410	51989	1.62×10^{19}	0.170	84	37.0	52.9
3-410	13253	1.62×10^{19}	0.221	110	42.2	63.6
3-410	27204	1.62×10^{19}	0.203	94	40.1	56.3
3-410	13253/12008	1.62×10^{19}	0.210	97	41.2	57.0
3-410	12008/27204	1.62×10^{19}	0.219	97.8	42.2	56.5
9-410	20291	2.28×10^{19}	0.216	105	45.4	57.3

f)

CAPSULE NUMBER AND MATERIAL	FLUENCE	INITIAL USE (FT-LB)	IRRADIATED USE (FT-LB)	CU CONTENT (%)	PREDICTED DECREASE IN USE (FT-LB)	PREDICTED IRRADIATED USE (FT-LB)	MEASURED DECREASE IN USE (%)
W-265 (TL) Plate	0.77×10^{19}	120	93	0.10	18.0	98.4	22.5
W-225 (TL) Plate	0.55×10^{19}	141	122	0.10	16.5	117.7	13.5
W-265 (TL) Plate	0.77×10^{19}	141	109	0.10	18.0	115.6	22.7
W-275 (TL) Plate	1.28×10^{19}	120	88	0.10	20.0	96.0	26.7
W-275 (TL) Plate	1.28×10^{19}	141	107	0.10	20.0	112.8	24.1
W-225 Weld	0.55×10^{19}	104	65	0.35	39.0	63.4	37.5
W-275 Weld	1.28×10^{19}	103.5	60	0.35	41.0	61.4	43.3
W-265 Weld	0.77×10^{19}	104	59	0.35	44.0	57.96	42.0
Mihama 1 (1st monitoring)	0.6×10^{19}	97.8	68.4	0.19	29.5	68.95	30.1
Mihama 1 (2nd monitoring)	1.2×10^{19}	97.8	61.0	0.19	35.0.	63.6	37.6
Mihama 1 (3rd monitoring)	2.1×10^{19}	97.8	61.0	0.19	39.5	59.2	37.6

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.

   Response:

   The plant operating cycles are recorded in accordance with Standing Order (SO) O-23, "Systems and Equipment Usage Data." Per this procedure, the Operations Engineer and System Engineer review the operating history on a monthly basis and document the number of cycles. The current number of operating cycles is listed below:

Fatigue Cycle Summary

Item	Cycle Description from USAR	Status of Cycle Count Relative to SO O-23	Current Count
1	500 heatup and cooldown cycles at a heating and cooling rate of 100 deg F/hr.	This cycle is counted and the count is complete.	66
2	10 cycles of hydrostatic testing the reactor coolant system at 3125 psia and at a temperature at least 60 deg F above the Nil Ductility Transition Temperature (NDTT) of the limiting component.	This cycle is counted and the count is complete.	1
3	200 cycles of leak testing at 2100 psia and at a temperature at least 60 deg F greater than the NDTT of the reactor vessel.	This cycle is counted and the count is complete.	46
4	400 reactor trips when at 100 percent power.	This cycle is counted and the count is complete.	52
5	40 cycles of loss of turbine load with delayed reactor trip from 100 percent power.	This cycle is counted and the count is complete.	19
6	40 cycles of total loss of reactor coolant flow when at 100 percent power.	This cycle is counted and the count is complete.	5
7	10 cycles of secondary side hydrostatic testing at 1235 psig while the primary side is at 0 psig.	This cycle is counted and the count is complete.	2 per Generator

Item	Cycle Description from USAR	Status of Cycle Count Relative to SO O-23	Current Count
8	200 cycles of secondary side leak testing at 985 psig while the primary side is at 0 psig.	This cycle is counted and the count is complete.	1
9	5 cycles of loss of secondary system pressure.	This cycle is included in SO-023, but there are no cycles on record.	0
10	5,000 cycles of adding 1000 gpm of 70 deg F feedwater with the plant in hot standby condition.	This cycle is included in SO-023, but there are no cycles on record.	0
11	8 cycles of adding a maximum of 300 gpm of 32 deg F feedwater, with the steam generator secondary side dry and at 600 deg F.	This cycle is included in SO-023, but there are no cycles on record.	0
12	4000 cycles (2,000 each direction) of transient pressure differentials of 85 psi across the primary head divider plate due to starting and stopping the reactor coolant pumps.	Exceeding this fatigue limit would require an average of 33 pump starts and stops per year for 60 years. Since this is far in excess of actual pump use, this fatigue cycle will not be exceeded.	N/A
13	15,000 power change cycles over the range of 10 percent to 100 percent of full load with a ramp load change of 10 percent of full load per minute increasing or decreasing.	This cycle is not counted under SO -23. These cycles are associated with normal plant operating transients, so they will be accounted for in the Fatigue Monitoring Program	NOTE (1)
14	2,000 cycles of 10 percent of full load step power changes increasing from 10 percent to 90 percent of full power and decreasing from 100 percent to 20 percent of full power.	This cycle is not counted under SO -23. These cycles are associated with normal plant operating transients, so they will be accounted for in the Fatigue Monitoring Program	NOTE (1)

Item	Cycle Description from USAR	Status of Cycle Count Relative to SO O-23	Current Count
15	1,000,000 cycles of operating variations of + 100 psi and + 6 deg F from the normal operating pressure and temperature.	This cycle is not counted under SO -23. These cycles are associated with normal plant operating transients, so they will be accounted for in the Fatigue Monitoring Program	NOTE (1)
16	80 cycles of adding 300 gpm of 32 deg F feedwater with the plant in hot standby condition.	This cycle is not counted under SO -23. These cycles are associated with normal plant operating transients, so they will be accounted for in the Fatigue Monitoring Program	NOTE (1)

NOTE 1: These cycles will be conservatively estimated by review of plant operating records to predict current cycles under the FMP program. Once the current number of cycles has been established a review will be performed to determine if there is a potential for exceeding the allowable cycles and should be managed. If the cycles require management through the period of extended operation then they will be counted and managed by the FMP program.

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.

   Response:

   OPPD is committing to continue tracking the number of operating cycles and maintain the cycle limits established by the Current Operating Basis through the period of extended operation. An informal estimate of the predicted number of operating cycles was performed by doubling the current number of cycles. This was based on Fort Calhoun having completed approximately 30 years of operation or half the 60 year life. This estimate shows that the number of anticipated cycles for 60 years doesn't exceed the allowable cycles for current licensing basis shown in the table

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.

   Response:

   There are no design basis transients discussed in Section 4.3 of the LRA excluded from the scope of the Fatigue Monitoring Program (FMP). All of these transients will either be counted directly or bounded by the counting of other related transients. A Program Basis Document (PBD) is to be generated to capture both the current and the increased scope of

the FMP (1) as a result of the incorporation of automated cycle counting at FCS this year, (2) as a function of the results of the LR IPA relative to the management of fatigue, and (3) as a result of the environmentally assisted fatigue analysis that has been performed, and recently reviewed and approved, for the Reactor Coolant System. The integration of these enhancements into the FMP has yet to be accomplished. With the development of the PBD, the integration of these activities will be accomplished such that all of the aspects of fatigue relative to FCS operation into the period of extended operation are addressed as described in the LRA. The completion of the PBD and full implementation of the enhanced FMP will take place before the period of extended operation. OPPD is committing to Update the FMP program to include this scope and to identify this additional monitoring as a commit in Appendix A of the application.

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.

Response:

Component	Environmental CUF
RPV Inlet Nozzle	0.718
RPV Outlet Nozzle	0.185
RPV Lower head to Shell Juncture	0.020
Surge Line Elbow	1.847*
Charging Line Nozzle	0.688*
Safety Injection Nozzle	0.385
Shutdown Cooling Piping Transition	0.208

The Environmental CUFs are based on the design number of cycles and include the environmental effects per NUREG/CR-6583 and NUREG/CR-5704, with the exception of the asterisked values, which are based on the anticipated number of transient cycles for a 60 year plant life consistent with Table 5-32 of NUREG/CR-6260.

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.

Response:

The approach for the aging management of the surge line is addressed in Sections 4.3.2 and 4.3.3 of the LRA. OPPD plans to inspect the limiting surge line welds during the third and fourth inservice inspection interval, and prior to entering the extended period of operation. The results of these inspections will be utilized to assess the appropriate approach for addressing environmentally-assisted fatigue of the surge lines. The approach developed could include one or more of the following:

- Further refinement of the fatigue analysis to lower the CUF(s) to below 1.0, or
- Repair of the affected locations, or
- Replacement of the affected locations, or
- Manage the effects of fatigue by an inspection program that has been reviewed and approved by the NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC).

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 surveillance's 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).

Response:

The acceptance criterion in the LRA does comply with IWL-3221 and 10 CFR 50.55a(b)(2)(viii)(B). A regression analysis of forces measured on specific tendons was conducted and included in the tendon testing report. The analysis showed satisfactory results were expected for the next surveillance.

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."

Response:

For the Concrete Containment Tendon Pre-Stress TLAA, OPPD has chosen Option III, managing the TLAA with an aging management program. The OPPD program that is being used is the Containment Inservice Inspection Program (B.1.2). This program is consistent with GALL Report Program X.S1, Concrete Containment Tendon Pre-Stress. Per Evaluation and Technical Basis Item 6, Acceptance Criteria, of this program, "The Prestressing force trend lines indicate that existing prestressing forces in the containment would not be below the MRVs [minimum required values] prior to the next scheduled inspection, as required by 10 CFR 50.55a(b)(2)(ix)(B) or 10 CFR 50.55a(b)(2)(viii)(B)."

Had OPPD selected Option II for this TLAA, a calculation would have been performed and the trend lines through the period of extended operation would be available. Since the acceptance criteria for the program are being followed, the trend lines for entry into the period of extended operation will not be available until the conclusion of the inspection prior to the inspection interval that is inclusive of entry into the period of extended operation.

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.

Response:

The TLAA discussion of the General Electric RCP motor flywheels in Section 4.7.1.1 consists primarily of excerpts from Section 4.3.5 of the FCS Updated Safety Analysis Report (USAR). The "Reference 4.7-1" notation is apparently a transcription error, and is noted as "Reference 4-4" in the source USAR paragraph. USAR Reference 4-4 is a fracture mechanics methodology

used in the postulated failure analysis described in USAR Section 4.3.5 (see Note 6 to Table 4.3-4 for the USAR wording).

To satisfy 10 CFR 54.21(c)(i0 and (ii) requirements, OPPD in the application provided a brief description of each crack growth analysis and its conclusion, as well as determinations that the results would remain valid through the period of extended operation. The supporting or referenced analyses are in the USAR or are available on site for NRC inspection. The USAR analysis of the General Electric RCP motor flywheels appears to date back to the FSAR approved during initial plant licensing. The analysis referenced in the USAR for the ABB motor flywheel is included as an enclosure to this attachment.

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."

Response:

For the period of extended operation of FCS, OPPD will implement actions or perform analyses, as required 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."

Response:

OPPD used the following definitions for the application:

Exception to GALL - OPPD does not intend to meet or implement a specified requirement in GALL

Clarification to GALL - OPPD intends to meet the intent of GALL Report criteria, but may deviate from the exact wording or criteria specified in GALL as documented in the license renewal application. For example, AMP B.2.2, Cooling Water Corrosion Program, implements the requirements of GALL Report Section XI.M21, Closed Cycle Cooling Water System. A clarification to B.2.2 notes the chemistry related portions of XI.M21 have been incorporated into the FCS Chemistry Program (B.1.2).

Program Enhancements - Revisions or additions to plant procedures or program activities that will be implemented prior to the period of extended operation to make the applicable program consistent with GALL requirements.

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.

Response:

Revised program and activity descriptions resulting from RAI responses are noted below. Any additional changes that result from subsequent reviews or inspections will be submitted in the annual update.

A.2 Programs and Activities for Managing the Effects of Aging

Refer to response to RAI 2.1-2

A.2.15 Non-EQ Cable Aging Management Program

The FCS Non-EQ Cable Aging Management Program implements inspection requirements for accessible electrical cables and connections installed in adverse localized environments for cable and connection jacket surface anomalies, such as embrittlement, discoloration, cracking, swelling, or surface contamination, which are precursor indications of conductor insulation aging degradation from heat, radiation or moisture. In addition, electrical cables used in circuits with sensitive, low-level signals, such as radiation monitoring and nuclear instrumentation, are tested as part of the instrumentation loop calibration at the normal calibration frequency, which provides sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance.

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?

Response:

The NRC staff's understanding of the program is 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.

Response:

The specific Chemistry-related portions of the GALL Report Closed-Cycle Cooling Water Program incorporated into the Chemistry Program are shown below. The remaining portions of the GALL Report Closed-Cycle Cooling Water Program are incorporated into the Cooling Water Corrosion Program (B2.2).

XI.M21 Program Description

"The program includes (a) preventive measures to minimize corrosion"

"The program relies on maintenance of system corrosion inhibitor concentrations within specified limits of Electric Power Research Institute [EPRI] TR-107396 to minimize corrosion."

2. Preventive Actions

"...and maintenance of system corrosion inhibitor concentrations are maintained within specified limits of EPRI TR-107396 to minimize corrosion. The program includes monitoring and control of cooling water chemistry to minimize exposure to aggressive environments and application of corrosion inhibitor in the Closed Cycle Cooling Water (CCCW) system to mitigate general, crevice, and pitting corrosion."

5. Monitoring and Trending

"The frequency of sampling water chemistry varies and can occur on a continuous, daily, weekly, or as needed basis, as indicated by plant operating conditions."

6. Acceptance Criteria

"Corrosion inhibitor concentrations are maintained within the limits specified in EPRI water chemistry guidelines for CCCW."

7. Corrective Actions

"Corrosion inhibitor concentrations outside the allowable limits are returned to the acceptable range within the time period specified in the EPRI water chemistry guidelines for CCCW."

The GALL Report Open-Cycle Cooling Water System program is incorporated entirely into the Cooling Water corrosion Program, with the clarifications as noted in Appendix B.

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.

Response:

(Note: This response supersedes the response transmitted by the Reference 3 letter)

Inspection of the liner performed in May 2001 identified approximately 6 locations of corrosion and loss of material at the base of the liner, between the floor expansion seal and the curb at elevation 994' 6". The total area of corrosion was less than 6 square inches. Inspection identified small areas within the corroded areas with a maximum thickness loss of approximately 15%. The minimum thickness measured with UT was 0.216" compared to a nominal thickness of 0.25". The inspection identified some areas of seal separation from the liner and shrinkage below the curb, which allowed moisture to collect. Repairs were made to recoat the degraded areas of the liner and restore degraded areas of the moisture barrier during the 2002 refueling outage. This included removal of the top portion of the moisture barrier to inspect inaccessible sections of the liner. Only minor surface corrosion was found on the liner extending only 0.125" to 0.25" below the top of the existing joint sealer. FCS plans to reperform the liner inspection during the 2003 refueling outage.

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 leakage's 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 leakage's.

Response:

Grease leakage noted on the outer containment walls during the 1990's resulted from seal leakage from helical tendon upper grease cans. The leakage characterized as a "large amount" ranges from a few cups to one gallon from a typical volume of more than 50 gallons. This upper seal can leakage has no effect on the long term corrosion of the tendon wires or end attachment, as demonstrated by inspection of the tendon ends when the leaks were repaired. The grease fill procedure was modified to leave additional "head space" for thermal expansion to decrease the number of minor grease leaks on the containment upper helical can seals.

IN 99-10, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments", identified examples of tendon degradation due to loss of grease. Our saw tooth construction and

unique helical tendon design combine to make many of the aspects of the subject information notice not applicable to FCS. No damage to tendon wires due to lack of grease, corrosion, or other aging effects have been identified during tendon inspections performed at FCS. To investigate the anti-corrosion effectiveness of thin films of grease, OPPD committed to the NRC in 1992 to test a dome tendon that had lost a significant amount of grease. The results of surveillance testing of the dome tendon showed enough grease adheres to the tendon wires to protect them from corrosion even when large grease voids occur. The type of grease was not changed.

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?"

Response

Fort Calhoun has performed a susceptibility analysis to identify components susceptible to degradation by FAC. All FAC susceptible components that are suitable for modeling are modeled using EPRI's CHECWORKS version 1.0g. CHECWORKS incorporates the predictive analysis techniques described in NSAC-202-L. CHECWORKS has the ability to predict wear rates and remaining component life for non-inspected components as well as inspected components. In addition, all inspection results are stored in a Microsoft Access based program, called "FAC Manager," that was purchased from a vendor with considerable expertise in the area of FAC. FAC Manager calculates wear using the same equations as CHECWORKS, but calculates wear rate by a straight line wear over time formula, which is the average wear rate over the components life (or time between inspections if the point-to-point method is used). CHECWORKS takes into account such parameters as flow rates, component materials, fluid chemistry and thermodynamic conditions in determining wear rates.

For non-modeled components, FAC Manager is used for predicting component degradation rates. For modeled components, both FAC Manager and CHECWORKS results are utilized in determining the component degradation rates.

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°F below the PTS screening limit and one weld is projected to be 15°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.

Response:

The RT_{PTS} value identified in Table 10 of CEN-636 is applicable to 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.

Response:

Table 1 below lists the bounding fast neutron fluence (E> 1 MeV) for 48 EFPY, and the associated fast neutron flux assumed for future core loadings associated with each of the reactor vessel materials. Fort Calhoun Station is currently projected to remain less than 48 EFPY at the end of the proposed license expiration on August 9, 2033.

Table 1

Plate/Weld	flux(n/cm^2-sec)	fluence (n/cm^2)
D4802-1	1.80E+10	3.50E+19
D4802-2	1.80E+10	3.50E+19
D4802-3	1.80E+10	3.50E+19
D4812-1	1.80E+10	3.50E+19
D4812-2	1.80E+10	3.50E+19
D4812-3	1.80E+10	3.50E+19
2-410	1.31E+10	2.48E+19
3-410	1.31E+10	2.48E+19
9-410	1.80E+10	3.50E+19

The fluence values used in Table 1 above were obtained from WCAP-15443, Revision 0 which was reviewed and approved by the NRC for Technical Specification Amendments 197 and 199. The overall exposure evaluation methodology is based on guidance provided in Draft Regulatory Guide DG-1053 and makes use of the latest ENDF/B-VI neutron transport and dosimetry cross-sections included in the BUGLE-93 library. This

fluence report also contains how the fluence was calculated (starting with page 2-1), includes the benchmark of the fluence model (starting with page 3-1) and the azimuthal distribution for fluence across the reactor vessel (see Table 6.2-1 on page 6-6). The fluence values for each material conservatively correspond to the end of fuel Cycle 41 (September 2033).

For all plate material and the 9-410 circumferential weld, the maximum circumferential fluence occurs at 45°. A bounding value at 48 EFPY, which would not be reached until after the period of extended operation, is 3.50E+19 n/cm^2. The 2-410 welds are located at 0°, 120°, and 240°, and the 3-410 welds are located at 60°, 180°, and 300°. The corresponding maximum fluence for both of the sets of welds occurs at 60° and is 2.48E+19 at 48 EFPY.

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

Response:

Table 2 lists those materials from Table 10 of CEN 636 where surveillance material (which includes the applicable source) was used to derive the chemistry factor.

Table 2		
Plate/Weld	**Plate or Weld Electrode Heat Number**	**Surveillance Data/Source**
D4802-2	A1768-1	Fort Calhoun Surveillance Plate D4802-2
3-410	12008/27204	Mihama 1 (3 capsules)
3-410	27204	Diablo Canyon 1 (2 capsules) Palisades Supplemental Capsule using FCS drop-out (1 capsule)
3-410	13253	Salem 2 (3 capsules)

The NRC has concurred with the use by OPPD of surveillance material results from sources other than Fort Calhoun Station through approval of Amendment 199 (dated June 6, 2001) to the Facility Operating License DPR-40 for Fort Calhoun Station Unit No. 1. The surveillance material information evaluated by the NRC was contained in the documentation noted in the introductory paragraph to RAI B.1.7-1.

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.

Response

Compliance with 10 CFR 50.61 is monitored as part of the Program Basis Document for Reactor Vessel Integrity. This program is administered by the FCS Design Engineering-Nuclear Engineering Department. The Nuclear Engineering Department also performs core reload analyses in-house, including core design. During core loading development core patterns are quantitatively evaluated to ensure that neutron flux to the limiting 60°/300° 3-410 welds is maintained approximately the same as that of Cycle 15, which formed the basis of the fluence analysis. This is done by summing the peripheral fuel assembly relative power densities multiplied by weighting factors derived from the fluence analysis adjoint flux solution. Thus values from a new fuel cycle can be compared to that of Cycle 15 to determine if there has been a net increase or decrease, with a goal of having a time average value the same as Cycle 15. Periodic updates of the fluence analysis are planned. RT_{PTS} is also tracked on an ongoing basis.

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.

Response:

Section 4.2 of the Program Basis Document for Reactor Vessel Integrity includes a schedule for obtaining applicable surveillance data from other plants to ensure that the chemistry factors of CEN-636 remain applicable. The FCS surveillance program was recently revised and approved by the NRC staff (Letter from NRC (S. Dembeck) to OPPD (R. T. Ridenoure) dated May 2, 2002, "Fort Calhoun Station, Unit No. 1 - Reactor Vessel Surveillance Capsule Removal Schedule Change (TAC No. MB3422)"). The next FCS surveillance capsule to be removed is W-275S at 33.6 EFPY. This supplemental capsule contains the limiting weld material 12008/13253 (Maine Yankee nozzle drop-out) as well as 27204 (FCS nozzle drop-out). In addition, if any major changes in plant operation do affect PTS or USE projections, reanalysis will be performed to ensure compliance with 10 CFR 50.61 or 10 CFR 50, Appendix G, as applicable.

Although OPPD has no formal agreements to obtain surveillance capsule data from other facilities, past and current interactions with these facilities provide high confidence that future data will be available for compliance with applicable regulations. The Safety Evaluation Report for Amendment 199 (dated June 6, 2001) to the Facility Operating License DPR-40 for Fort Calhoun Station Unit No. 1 notes, "According to paragraph (B)(v)(2) and footnote 5 of 10 CFR 50.61 (the PTS rule), OPPD must assess the impact of changes (if any) to the FCS PTS evaluation that result from changes in surveillance data from Mihama Unit 1, Diablo Canyon Unit 1 and Palisades."

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.

Response:

The Boric Acid Corrosion Prevention Program at FCS has been implemented in accordance with the recommendations contained in NRC Generic Letter 88-05 and adequately manages the aging effect of boric acid corrosion. The enhancements identified in LRA Section B.2.1 will be implemented to make wording in the FCS program relative to inspection of components on which boric acid may have leaked consistent with that found in GALL Report Section XI.M10, Boric Acid Corrosion, and will correct minor deficiencies identified during assessment of the program against the GALL Report criteria. These enhancements will not significantly impact the FCS Boric Acid Corrosion Prevention Program, but will increase the scope of inspections to include some components currently not routinely inspected under the program and improve trending when leaks are detected during performance of maintenance activities.

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.

Response:

Please refer to the two drawings showing the tank arrangement and inaccessibility.

- D-4045, Enclosure for Fuel Tank for Diesel Driven Fire Pump at West Side of Intake Structure
- 11405-A-279, Intake Structure Floor Plans El 993' 6" and 1007' 6''.

These drawings have been provided by the Reference 5 Letter.

(1&2) The Diesel Fuel Monitoring and Storage Program is the aging management program which will detect Fire Protection Fuel Oil tank degradation in sufficient time to allow for corrective action before loss of the tank's intended function. Ultrasonic testing can not be performed on this tank due to inaccessibility, so leak detection was chosen as an alternate method to maintain the tank's intended function.

The Fire Protection Diesel Fuel Oil Tank is above ground, surrounded by gravel, and enclosed in a concrete structure that has no openings (i.e., no doors, hatches, etc. that would provide any type of access to the tank). The concrete structure is surrounded by a concrete berm. The concrete enclosure has a drain valve that drains to the berm area. The Diesel Fuel Monitoring and Storage Program credits two leak detection activities. The first activity involves operator rounds recording whether any oil sheen is seen in this berm area. Although some leaking fuel could occur out of sight, any significant amount would produce an oil sheen in the berm area. The second activity is to identify via level readings any leakage from the tank between monthly surveillance's, while accounting for periodic oil replenishment. Leak detection is adequate to maintain system design requirements, because OPPD has 7 days to restore the inoperable equipment to operable status. Seven days is ample time to make necessary repairs or bring in a portable diesel fuel supply.

In addition, OPPD feels that this aging management is adequate based on past operating experience. The Fire Protection Tank is the same material as the Diesel Generator Tanks. The results of past visual inspections and UTs to the Diesel Generator Tanks have not indicated degradation. New fuel additions to the Fire Protection Tank will be analyzed for water and sediment to preclude water contamination, and tank bottoms will be monitored to ensure water or biological activity are not accumulating.

(3) Inspections (i.e., UT and/or visual) are performed in the other storage tanks which credit this program for aging management.

(4) The low point for the Fire Protection Fuel System beyond the main tank is the bottom of the day tank. The day tank sample will be drawn from the bottom of the tank and will be analyzed for water and sediment. See the response to B.2.3-2 for details on monitoring of the day tank.

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.

Response:

The day tank activities addressed in this question are enhancements and are not the only aging management activities for these tanks. This question is answered by OPPD being consistent with the GALL Report, Volume 2, Section XI.M30, Fuel Oil Chemistry Program; however, the following is provided to address the staff's specific request for detail.

The Diesel Generator (DG) day/engine tanks are cleaned, flushed, and visually inspected every third refueling outage. Visual inspections are performed using a flashlight through tank openings. Tank surfaces can be seen and do not indicate visible corrosion. The DG day tanks have a water and sediment analysis performed monthly.

The DG engine tanks have a water and sediment analysis performed semi-annually and a microbiological activity analysis performed semi-annually.

The fire protection day tank will be analyzed quarterly for water and sediment, semi-annually for microbiological activity, and will have a one-time boroscope inspection performed.

The acceptance criterion for water and sediment is "no adverse trend" and for microbiological activity is "none detectable." Due to the monthly surveillance runs, the fuel in these day/engine tanks does not remain stagnant and would not warrant quarterly analyses. There is no history of degradation at FCS in the fuel oil system; however, if degradation is found which exceeds Class C cleanliness, then a Condition Report is written and corrective action is taken based upon the Corrective Action Program and any case-specific evaluations.

NOTE: Class C cleanliness has the following criteria:

- Thin uniform rust or magnetite films are acceptable.
- Scattered areas of rust are permissible provided that the area of rust does not exceed 15 square inches in 1 square foot on corrosion resistant alloys.

B.2.4 Fatigue Monitoring Program

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.

Response:

In 1997, a plant Condition Report was generated to document that certain piping and components in the CVCS system may have been exposed to more thermal cycles than assumed in the system and/or equipment design basis. The procedure for monitoring fatigue cycles required monitoring of cycles specifically identified in the plant Technical Specifications and USAR, but did not include monitoring of all components, whose design basis may have included a limited number of defined transients The CR resulted in the performance of an Engineering Assessment to

document a review of system Design Basis Documents, the USAR, Technical Specifications, and other documents to determine cycle counting requirements. An operating history review determined the number of cycles that the components of concern actually experienced. Revisions incorporating revised cycle counting requirements identified during the reviews were incorporated into the applicable design basis documents and monitoring procedure. The discussion in Section 4.3.1 of the application, relative to the CVCS, reflects the findings of the assessment. The components that were in question are monitored and tracked as required by the FMP.

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.

   Response:

   Enhancements to procedures will ensure the diesel fire pump is under direct observation during performance testing.

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.

   Response:

   The enhancement identified in the license renewal application for Fire Protection Program (B.2.5) was to add specific guidance to the halon and fire damper inspection procedures to inspect halon system components and fire dampers for corrosion, mechanical, and physical damage. This enhancement will be implemented prior to the period of extended operation.

Halon and fire damper inspection procedures include periodic visual inspections and functional tests every 18-months to examine signs of degradation of the halon fire suppression system. Although the suppression agent charge pressure is checked on a semi-annual basis and inspections are performed on a monthly basis that verify that the extinguishing agent supply valves are open and that the system is in automatic mode, these activities are not required for license renewal. Per interim staff guidance, these activities are not aging management related since the valve line-up inspection, charging pressure inspection, and automatic mode of operation verification are operational activities pertaining to system or component configurations or properties that may change.

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.

   Response:

   The enhancement identified in the license renewal application for Fire Protection Program (B.2.5) was to add specific guidance to the fire door inspection procedures to inspect for wear and missing parts. This enhancement will be implemented prior to the period of extended operation.

   Inspections of fire doors for holes, clearances, and proper operation of opening, latching, and closure mechanisms within the specified frequencies are currently included in the FCS Fire Protection Program with the exception of the frequency of inspection for fire door clearances. Inspection frequencies for fire door clearances will be revised to meet the bimonthly requirement.

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 maintenance of the component intended function.

Response:

Portions of the Fire Protection System piping that are underground are made of asbestos-cement or cast iron with a cement lining. For these materials, an aging management evaluation determined that aging management is not required because the interior of these pipes is not exposed to an aggressive environment (pH<5.5, sulfates>1500 ppm, and chlorides>500 ppm). Under normal conditions, the system is filled with potable water whose pH, sulfate, and chloride content is within these limits. If untreated raw water is injected into the system, the system is flushed and refilled with potable water. The cement lining was installed in accordance with American Water Works Association (AWWA) Standard C104, Cement-Mortar Lining for Ductile-Iron Pipe and Fittings for Water. The minimum lining thickness for the size of pipe at FCS is 1/16" and meets the requirements of ASTM C150. The lining was applied to the pipe at time of manufacture. The cement lining of cast iron piping provides it with an added feature to prevent the loss of material of the base metal due to corrosion. The cement lining also prevents internal buildup of turbucles that would contribute to degradation of the pipe flow characteristics. In addition to the inspection activities, the testing features of the Fire Protection Program provide assurance that the entire system can perform its intended function. A visual as-found inspection performed on a section of the FP piping during modification/maintenance work in May 2000 identified that the internal surfaces of the underground piping were clean with a little oxidation on the piping wall.

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.

Response:

There are no steel structures within the scope of license renewal, and subject to an AMR, that depend on coatings to protect the steel structure from age-related degradation or fire.

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. Staff Position for Wall Thinning of Fire Protection Piping Due to Internal Corrosion

   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.

Response:

The issues contained in this RAI appear to be duplicates of RAIs B.2.5.2 and B.2.5-3. Refer to the B.2.5-2 and B.2.5-3 responses.

2. Staff Position for Testing of Sprinkler Heads

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.

Response:

Prior to the period of extended operation, OPPD will make enhancements to the Fire Protection Program to develop a task/procedure to test/replace sprinkler heads, which have been installed and functional for 50 years, and to test sprinkler heads every 10 years thereafter. The in-service date of 1972 will be used to determine the schedule for this task.

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.

Response:

The Periodic Surveillance and Preventive Maintenance (PM) Program credited for license renewal is a select subset of activities performed under the FCS Surveillance Test Program and the Preventive Maintenance Program which were both in place prior to introduction of the Maintenance Rule (10 CFR 50.65). The purpose of the Surveillance Test Program is to complete

all surveillance requirements set forth in the Fort Calhoun Technical Specifications, Fire Protection Program, and Off-site Dose Calculation Manual (ODCM). The purpose of the Preventive Maintenance Program is to prevent or minimize equipment breakdown and to maintain equipment in a satisfactory condition for normal and/or emergency use. The Maintenance Rule implemented additional requirements for components that fell within the scope of the rule to establish performance criteria, monitor performance and unavailability, evaluate operational experience, and evaluate maintenance activities to further ensure the reliability of the components to perform their intended function.

The activities performed by the Periodic Surveillance and Preventive Maintenance Program can be described in the following general categories: component inspections for degradation (i.e., valve internals, ventilation dampers, intake structure screens, manhole covers, etc.), lube oil analysis, and visual observations (i.e., Operations logs, Spent Fuel Pool level monitoring). In addition, the PM tasks which perform the replacement of components identified as "periodically replaced" during the Scoping, Screening, and Aging Management Review process are incorporated into this program. The PM activities credited for aging management are in some instances the same activities credited for implementing Maintenance Rule requirements. These activities will be enhanced as needed to include applicable criteria for assessing age related degradation that was identified during the aging management evaluation process. Processes are in place to perform periodic assessment of the PM activities to determine the overall health of the program, and adjustments are made to improve overall effectiveness of the tasks as required. Preventive Maintenance tasks performed on components within the scope of the Maintenance Rule are reviewed on a refueling outage frequency as required by the rule. Effectiveness reviews of PM activities outside the scope of the Maintenance Rule are not performed on a set frequency, but are based on trending of corrective action and maintenance documents initiated due to failure to meet established PM acceptance criteria.

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?

Response:

Inspection of concrete is not performed by any activities credited to the Periodic Surveillance and Preventive Maintenance Program. Structural concrete is inspected under the Containment Inservice Inspection Program (B.1.3) and Structures Monitoring Program (B.2.10) which does include monitoring changes in physical properties.

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."

Response:

To date, no cracking has been discovered in bolting for Combustion Engineering (CE)-designed RV internals. In 1998, the Combustion Engineering Owners Group (CEOG) provided an assessment to OPPD of the cracking of the baffle former bolts reported in foreign (EdF) PWRs, including the potential impact of the cracking on domestic CE plants. The most likely mechanism for the cracking of cold-worked 316 stainless steel baffle former bolts in foreign plants is IASCC. Palisades and FCS are the only two CE-designed plants that use bolts to attach the core shroud panels (i.e., the baffle plates) to the former plates. These bolts at FCS are less susceptible to IASCC because: (1) the material used in these bolts is annealed 316 stainless steel, which is not cold worked; (2) the bolt stress from preload, as a percentage of yield strength, is much less than the EdF plants; (3) the differential pressure across the core shroud panels does not result in tensile loads on the panel (i.e., the baffle bolts) during normal operation; and (4) the core shroud panel design allows for some flexing of the former plate relative to the core barrel, thus reducing the load on the panel bolts.

Other industry operating experience includes cracking discovered in Point Beach Unit 2 baffle bolts in December 1998. Ultrasonic inspection of 728 baffle former bolts revealed 24 cracked bolts, which was believed to be caused by IASCC. However, as with the EdF experience, cracked bolts were highly stressed during preload, tensile stresses were applied during operation because of the Westinghouse design, and the bolts were fabricated with cold worked 316

stainless steel. The applicability of this operating experience relative to FCS and Palisades is, therefore, consistent with the results of the above referenced assessment.

Based on the above operating experience, the CEOG assessment, and CE's position that normal in-service inspections will detect any problems with these bolts, OPPD has determined that augmented inspections of this bolting are not necessary. Visual inspections of the core shrouds at Palisades and FCS in 1995 and 1993, respectively, revealed no panel separation and no missing bolts. Ten-year in-service inspections were performed at FCS in 1992 and will be performed again in 2003 and prior to the period of extended operation. The results of these inspections, the Palisades in-service inspection results, and the results of industry programs will be monitored to determine if additional action, such as ultrasonic inspection, is necessary.

Stress corrosion cracking was identified in B&W lower thermal shield and lower core barrel bolts that were made with Alloy A-286. Most of the failed bolts were highly stressed to the material yield strength or beyond. Cracked bolts were replaced with bolts of improved design fabricated with Inconel X-750. No cracking of these bolts has recurred. Although there have been no failures of CEA Shroud Bolts in CE-designed RV internals, there has been industry concern that SCC may occur since these bolts are also fabricated of Alloy A-286. CE provided an evaluation of the stress levels for these bolts in 1984. According to this evaluation, operating stress levels are just below 32 Ksi. The stress concentration factor for the CEA Shroud Bolts is 2.06 leading to a local stress of approximately 66 Ksi. Yield strength for A 286 is about 115 Ksi, so the stress is approximately 60% of the yield strength. Most of the failed B&W bolts had working stresses of approximately 65 Ksi and a local stress of 134 Ksi, which is above the yield strength of the material. There were no failed B&W bolts with working stresses of 35 Ksi. The conclusion of the evaluation indicates a low probability for cracking of the CEA Shroud Bolts. The EPRI MRP is developing an action plan to address potential SCC of reactor vessel internals. OPPD is participating in this program and will take action, as necessary, in response to any recommendations and findings coming from the evaluation.

There are two typographical errors in the table on the first page of Section B.2.8 of the LRA as identified in item b. of this RAI. For the NUREG-1801 Program XI.M16, Reactor Vessel Internals, the "Parameters Monitored" and "Detection of Aging Effects" criteria that were identified as AMP criteria numbers 7 and 8, respectively, should be identified as AMP criteria numbers 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.

Response:

OPPD's Steam Generator Program is consistent with the GALL Report Section XI.19, "Steam Generator Tube Integrity" program and NEI 97-06. As such, OPPD's Steam Generator Program includes foreign material exclusion and loose parts monitoring as described in NEI 97-06, Section 3.2.3.2. These activities are not credited to the aging management of specific components.

Section 3.2.3.2 of NEI 97-06 states, "Licensees should have alarm response procedures for the loose parts monitoring system." OPPD has an annunciator response procedure that complies with this guidance. Page B-3 of the LRA is correct in showing that OPPD does not credit GALL Report Section XI.M14, Loose Parts Monitoring Program, for aging management. OPPD credits the annunciator response procedure for NEI 97-06 compliance, not as an aging management program.

Regarding water chemistry as a mitigating activity, every GALL Volume 2 reference to the Steam Generator Tube Integrity Program jointly contains reference to the GALL Water Chemistry Program. OPPD likewise reflects this by discussing the preventive actions of water chemistry in the Chemistry Program, not the Steam Generator Program.

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.

Response:

OPPD is consistent with the GALL Report Section XI.19, Steam Generator Tube Integrity Program and with guidance contained in NEI 97-06.

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.

Response:

OPPD is consistent with the GALL Report Section XI.19, Steam Generator Tube Integrity Program and with guidance contained in NEI 97-06.

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.

Response:

This response addresses all of the RAI question except Item 2, regarding tubes and sleeves, which is addressed by the response to RAI B.2.9-1. This response includes the components added by the response to RAI B.1.2-1. Steam Generator components addressed by this response include: secondary shell, primary head, secondary handholds, secondary head, secondary manways, transitional cone, tube supports (batwing, eggcrates, vertical grids), nozzles (blowdown, feedwater, instrument, steam), nozzle safe ends (feedwater, steam), tubesheet (primary and secondary side), plugs, and feedring. Attributes of the FCS Steam Generator Program are as follows:

PREVENTIVE ACTIONS:

For all added-scope components water chemistry and foreign material exclusion are performed as preventative actions. Water Chemistry is maintained per the FCS Chemistry Program in accordance with GALL XI.M2, Water Chemistry, as a mitigative activity for both primary and secondary water. Foreign material exclusion is performed per NEI guidance to prevent mechanical damage. Sludge removal is performed, when necessary, as a preventive action for the secondary-side tubesheet degradation. Inspections also occur so proactive actions can be taken to minimize further degradation. The scope and frequency of components inspected are addressed in other sections below.

PARAMETERS MONITORED/DETECTION OF AGING EFFECTS/MONITORING AND TRENDING/ACCEPTANCE CRITERIA:

Secondary shell, secondary handholds, secondary head, secondary manway, and transitional cone: These components are visually inspected for loss of material (general, pitting, and crevice corrosion) to ensure pressure boundary integrity. Since these components are all the same material in the same environment, at least one of these components is "representatively" visually inspected each refueling outage. Scope is expanded based on discovery of unexpected change in degradation, where change is based on review of past inspections. Site operating experience indicates relatively little degradation relative to the thickness of these pressure boundaries. Furthermore, site Class Cleanliness Standards (see below) allow only a small amount of degradation before a Condition Report is required. The Corrective Action Program provides acceptable means of review, evaluation, and corrective action. Therefore, the representative visual inspections are considered adequate aging management of these pressure boundaries.

Plugs: Please note that AMR Item 3.1.2.07, regarding loss of material on the secondary side of the plugs, has been removed due to no site operating experience with this aging effect and because it is not a GALL-recognized aging effect. Plugs are visually inspected for cracking. Industry has indicated cracking problems in Westinghouse mechanical plugs and in Babcock and Wilcox Inconel 600 plugs. OPPD does not use either of these plugs at FCS. Industry operating history for CE plugs is such that there has never been any cracking problems or degradation. OPPD complies with current industry practice and will comply with future industry practices for inspection of plugs. Visual inspections are the only industry practice currently in place. Furthermore, if cracking were identified in a plug, a Condition Report would be written. The Corrective Action Program provides acceptable means of review, evaluation, and corrective action. Because each plug is visually inspected each outage, these visual inspections are adequate aging management to maintain the pressure boundary function.

Nozzles, nozzle safe ends, and feedring: The aging effect managed by this program for these components is loss of material due to general, pitting, and crevice corrosion. The feedring additionally has galvanic corrosion as an aging effect. Ultrasonic testing (UT) for wall thinning of the feedring in 2002 revealed little or no degradation. The external surface of the feedring is visually inspected each refueling outage for corrosion. Scope is expanded based on discovery of unexpected change in degradation, where change is based on review of past inspections. Since the feedring internal and external surfaces are in the same environment, the visual examination of the external surface is considered representative of the internal surface for these aging effects. The nozzles and nozzle safe ends are not inspected, but are bounded by the visual inspection of the carbon steel feedring, which is more susceptible to aging than the low alloy steel or carbon steel nozzles and nozzle safe ends. Please note that where FAC is applicable to these components, it is managed by the FAC Program and not the Steam Generator Program. Site Class Cleanliness Standards (see below) allow only a small amount of degradation before a Condition Report is required. The Corrective Action Program provides acceptable means of review, evaluation, and corrective action. Because the UT revealed little or no degradation 29 years into operation, and site Class Cleanliness standards would require corrective action far before the pressure boundary integrity of the nozzles and nozzle safe ends or flow distribution of the feedring are compromised, this visual inspection is adequate aging management.

Secondary-Side Tubesheet: The secondary side tubesheet is visually inspected (and supplemented by tube eddy-current testing (ECT)) each refueling outage for loss of material (general, pitting, and crevice corrosion). A camera is placed on top of the tubesheet and transported along the periphery of the tube bundle and down the blowdown line. In addition, ECT to the tubes would indicate if the adjacent tubesheet was degrading. The Corrective Action Program provides acceptable means of review, evaluation, and corrective action. Because the tubesheet is over 22 inches thick and ECT can reflect tubesheet loss, this visual inspection (augmented by ECT) is adequate to maintain the pressure boundary function of the tubesheet.

Primary-Side Tubesheet and Primary Head: These components are visually inspected for cracking. Portions of the primary side tubesheet and primary head are inspected using a remote camera each refueling outage. The tubesheet and primary head are thick, so the initiation of a crack, which could grow to be a pressure boundary threat, could easily be detected with the camera. Because the tubesheet and primary head are the same material in the same environment and there is no operating history of cracks to these components at FCS, this visual inspection is adequate to maintain the pressure boundary function of the tubesheet and primary head.

Tube Supports (Batwing, Eggcrates, Vertical Grids): These components are visually inspected for loss of material (FAC, general, pitting, crevice, and galvanic corrosion). A portion of the batwings are inspected each refueling outage. In 1998, a remote video camera was used to video the peripheral eggcrate locations from three drop points, with nearly all eggcrate elevations inspected from each drop point. No degradation of the eggcrate tube supports was noted. Furthermore, ECT each refueling outage has not resulted in any indications of missing or severely damaged tube supports in the areas adjacent to the tubes. Because operation has continued for 29 years with insignificant degradation, and all these components are carbon steel in the same environment, visual examination (augmented by ECT) is adequate management of these tube supports for structural function.

Class B Cleanliness (Required for the Primary Side): "The surface shall appear metal clean when examined without magnification under a normal lighting level. Scattered areas of rust or magnetite are permissible provided the aggregate area of rust does not exceed 2 square inches in any one square foot area."

Class C Cleanliness (Required for the Secondary Side): "Thin uniform rust or magnetite films are acceptable. Scattered areas of rust are permissible provided that the area of rust does not exceed 15 square inches in 1 square foot on corrosion resistant alloys."

Additionally, actions noted in the OPPD response to GL 97-06 provide adequate management of secondary side internals.

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 Institute (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.

Response:

The FCS Alloy 600 Program currently includes a requirement to monitor industry operating experience and implement program enhancements as necessary. This issue of cracking of Alloy 600 and Alloy 82/182 material is being addressed as a current licensing basis issue.

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.

Response:

The following locations of Alloy 82/182 have been identified in the Alloy 600 Program Basis Document for the pressurizer, steam generators, and RCS piping:

- Pressurizer - internal attachments to lower shell, bottom head

- Pressurizer top head - temperature nozzle, relief valve assembly (nozzle to spool piece and spool piece to safe end), level nozzle assembly (nozzle to spool piece and spool piece to safe end), safety nozzle to flange, spray nozzle assembly (nozzle to spool piece and spool piece to safe end), temperature nozzle safe end, spray nozzle radius and flat clad, and surge nozzle and spray nozzle clad

- Pressurizer lower shell - temperature nozzle, cladding (12" wide band)

- Pressurizer bottom head - heater sleeves, heaters to heater sleeves, surge nozzle to safe end, temperature nozzle to safe end, level nozzle assembly (nozzle to spool piece and spool piece to safe end), and inner diameter cladding

- Steam generator - primary head divider plate lane cladding, primary head to tubesheet girth backclad, tubesheet cladding, drain tube bracket to clad overlay, divider bar to head and tubesheet, and clamp rings and pins at primary head nozzle openings

- Steam generator primary head - primary nozzle safe ends to nozzles

The most susceptible locations for PWSCC are the welds on the pressurizer heater sleeves and pressurizer temperature nozzles.

In 2001, FCS experienced a leak on the pressurizer lower shell temperature nozzle, TE-108. A code weld repair was made to the TE-108 nozzle, and a mechanical device was placed on pressurizer nozzle TE-107 as a precautionary measure. The mechanical seal device was removed during the next refueling outage when eddy current measurements verified no cracking was occurring at the nozzle. Review of historical information on this weld identified that a weld repair had been made at this location during original fabrication as a result of the nozzle being bent after the initial hydro test.

The root cause analysis of the V. C. Summer event indicated extensive rework of the affected nozzle, which resulted in changes to the as-designed weld configuration, was an important contributor to the failure. As a result, FCS performed a detailed review of FCS Alloy 600 and Alloy 82/182 component fabrication records. FCS is less susceptible to the cracking that occurred at V. C. Summer based on the following :

- All the nozzle to safe end welds at FCS were shop welds, in contrast to the affected weld at V. C. Summer, which was a field weld. A review of FCS fabrication records for nozzle to safe end welds did not reveal any evidence of significant weld repairs.

- FCS nozzle to safe end welds were heat treated following repairs. This was not performed on the affected V. C. Summer weld.

- The FCS nozzle welds with more rework were inlet nozzles whose lower temperature would result in less driving force for PWSCC.

The reactor coolant system (RCS) inspection procedure used by FCS following opening, repair, or modification of the RCS system has been enhanced to specifically identify Alloy 600 and Alloy 82/182 components, and increase inspector awareness for evidence

of potential leakage. Additional details and analysis results are documented in the FCS Alloy 600 Program Basis Document.

An assessment of Alloy 600 and Alloy 82/182 components has been performed and incorporated into the Alloy 600 Program Basis Document. The assessment included evaluation for history, susceptibility, safety considerations, inspection, repair, and mitigation, and provided conclusions and recommendations to address the specified components. The recommendations include items such as increased inspections (UT), repair, replacement, and more detailed assessments. These recommendations will be evaluated as part of the Alloy 600 program and implemented as necessary to ensure the reliability of the Alloy 600 and Alloy 82/182 components.

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).

   (Note RAI typographical error: First mention of NRC Bulletin 2002-02 should be 2002-01)

   Response:

   The level of detail provided in response to Part 2 of this RAI is not consistent with the level of detail provided in the FCS USAR and will not be included in the USAR supplements. OPPD will incorporate appropriate information from the OPPD responses to GL 97-01 and NRC Bulletins 2001-01, 2002-01, and 2002-02.

B.3.2 Buried Surfaces External Corrosion Program

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.

Response:

The scope of the Buried Surfaces External Corrosion Program includes:

Raw Water System – approximately 900 ft of carbon steel piping running between the Intake Structure and the Auxiliary Building

Diesel Generator Fuel Oil System – the diesel fuel oil tank and approximately 100 ft of carbon steel piping between the tank and the Auxiliary Building

Auxiliary Boiler Fuel Oil System – the auxiliary boiler fuel oil tank, approximately 50 ft of carbon steel pipe between the tank and the Turbine Building, and approximately 50 ft of copper tubing between the tank level indicator and the Turbine Building

Fire Protection System – approximately 56 ductile iron valves and hydrants and the short sections of ductile iron piping connecting them to the asbestos-cement fire protection header.

Buried piping and tanks will be inspected whenever they are excavated for maintenance. PM tasks to defuel, clean, and inspect the emergency diesel and auxiliary boiler diesel fuel tanks are performed on a 9-year frequency. An inspection of the emergency diesel and auxiliary boiler fuel tanks was performed in 1995. An ultrasonic test (UT) of the emergency diesel fuel oil tank was performed with no indication of degradation identified. Performance of UT on the internal surface of the tanks will also identify any loss of material, which may be occurring due to corrosion on the external surfaces. The next tank inspections are scheduled to be performed in 2004, to include a UT and excavation of portions of the tanks surfaces. The top of the tank's exterior surface around the vent and fill pipes is excavated to conduct a visual inspection of the pipes, tank surface, welded connections, and hold down bands

Excavations of buried piping have been performed in 2000, 2001, and 2002 exposing sections of the fire protection and raw water system piping. Excavations were performed to repair degraded valves, repair potable water piping, and make modifications to fire protection system piping. Discussions with system engineers and photos taken of exposed sections of the buried piping have shown the pipe coatings to be well maintained with no evidence of degradation.

Discussion with maintenance planners indicated excavations are typically performed every 2 to 3 years.

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."

Response:

The General Corrosion of External Surfaces Program is a condition monitoring program, which identifies evidence of corrosion on external surfaces, or significant degradation of coatings, sealants, and caulking through visual inspections, and initiates corrective action prior to any loss of intended 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.

Response:

Section (3) "Parameters Monitored or Inspected" of B.3.3 states, "Surface conditions of components are monitored through visual observation and inspection to detect signs of external corrosion and to detect conditions that can result in external corrosion, such as fluid leakage." Fluid leakage was identified only as an example of a condition which could lead to component degradation if not corrected and that would be identified from the program walkdowns. Fluid leakage, such as packing leaks, is an indicator of a degraded condition that could lead to corrosion on surrounding components if allowed to continue.

The program includes monitoring of components and their external coatings for evidence of cracking, checking, blisters, rusting, pinholes, abrasions, delamination, and significant substrate defects (such as corrosion pits). Monitoring of these indications ensures component degradation is identified and corrected prior to any loss of pressure boundary.

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?"

Response:

Guidance from Regulatory Guide 1.54 is incorporated in the containment coatings inspection per Section 5.2.5 of the FCS USAR.

Degraded protective coatings discussed in Generic Letter 98-04 are a precursor of corrosion, but do not have any direct effect on the ability of the coated components to perform their intended functions. For System Engineer and Operator walk downs, acceptance criteria for when to initiate a maintenance work order or corrective action document is based on engineering judgment and the Operator's experience. Initiation of a corrective action document is based on procedural guidance to identify damage or degradation that adversely affects the functional capability of a structure, system, or component.

Procedural guidance is being enhanced as part of the implementation of this new program. Procedures will be revised to include acceptance criteria that a visual indication of loss of material or cracking of elastomer ventilation components identified by the accountable Operator or Engineer will not necessarily lead to an unacceptable component. Unacceptable components are those which are damaged or degraded such that they are not capable of performing their intended function, or if degradation were allowed to continue uncorrected until the next normally scheduled inspection the component would not meet its design basis.

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.

Response:

The scope of auxiliary systems listed in LRA Section B.3.3 excludes components that are not routinely accessible. Aging management activities on inaccessible components (such as ultrasonic testing of the buried emergency diesel and auxiliary boiler fuel oil tanks, and level monitoring and leakage detection on the diesel fire pump fuel oil tank) are incorporated into other plant programs (i.e., Buried Surfaces External Corrosion Program (B.3.2), Diesel Fuel

Monitoring and Storage Program(B.2.3)). Inspections and monitoring of these components has not identified any degradation.

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?

Response:

For non-EQ cables and connections within the scope of license renewal and subject to an aging management review:

1. Prior to the period of extended operation, OPPD will implement a program and inspection consistent with that described in XI.E.1 of the GALL Report.

2. Prior to the period of extended operation, OPPD will implement a program and inspection consistent with that described in XI.E.2 of the GALL Report.

3. In 1994, during an inspection of the cable vault/manhole, it was discovered that moisture ingress around the manhole was causing some of the conduit to corrode. An Engineering Change Notice (ECN) was issued that modified the cable/conduit run. A section of boat foam was added around the conduit nest to preclude water seeping in through the manhole cover from further corroding the conduit. Additionally, the manhole was sealed.

   Medium voltage cables (six safe shutdown circuits) are routed through the vault and into duct banks from the intake structure to the service building. Although medium voltage cables are routed through the duct bank, the duct banks, by design, will not accumulate standing water; duct banks are pitched at a minimum of 1/8" per foot. In thirty years, OPPD has not had a cable failure, however, to ensure that cable susceptible to potentially wetted conditions do not deteriorate, OPPD will implement a program and inspection consistent with that described in XI.E.3 of the GALL.

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.

Response:

Accurate hardness measurements cannot be made on plant components due to the limitation of the equipment required to perform hardness measurements (i.e., geometry and limited access to internal component surfaces to be tested). In addition, copper alloys and cast irons are not homogenous, like steels. Consequently, hardness measurements taken at different locations would have a wide degree of variance in hardness readings. Any overall trend downward in the hardness results would correlate to degradation that would easily be seen. There is no hardness acceptance criterion, so there is no corrective action basis gained by the hardness trend from that

obtainable by the visual inspection. Any degradation that could impact pressure boundary integrity can easily be seen. Therefore, hardness measurements would not be an added-value activity to visual inspections.

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.

Response:

Selective leaching is an "external" aging effect for this buried copper-zinc tubing. The Selective Leaching Program credits the inspection performed by the Buried Surfaces External Corrosion Program. In accordance with the Buried Surfaces External Corrosion Program, this piping is periodically unearthed and the external surface of this piping is visually inspected for loss of material (including selective leaching). This satisfies the one-time inspection attribute of the program.

Commitment Summary

3.1.1-3	The Alloy 600 Program is a new program at FCS. With this being the case, inspection methodologies for all of the components in the program have not yet been determined. Some of the components that are in the program are currently part of other programs like the Reactor Vessel Internals Inspection Program. The activities that occur under the interfacing programs relative to these components will be utilized to help analyze and determine the methodologies to be incorporated within the Alloy 600 Program for inspection of its included components. These analyses and determinations will be completed prior to entry into the period of extended operation.
3.1.1-4	OPPD will continue to be involved in industry/regulatory activities relative to this issue and will apply recommended or mandated activities to the maintenance of the FCS CEDM housings as applicable.
3.1.2-1	OPPD will continue to visually inspect and perform a dye-penetrant exam on the two remaining RCP thermal barriers when the rotating assemblies are refurbished. FCS will credit the One-Time Inspection Program for these RCP thermal barrier inspections.
3.1.2-5	OPPD has conservatively included Loss of Material as an AERM for Alloy 600 in borated, treated water...To validate the effectiveness of the Chemistry program, OPPD will determine the worst-case location for the potential occurrence of this AERM and perform a one-time inspection of this location prior to the period of extended operation.
3.5.1-8	A periodic task will be initiated as part of the Structures Monitoring Program to take ground water samples on a five year frequency and compare the evaluation results to previous samples.
4.7.2-1	For the period of extended operation of FCS, OPPD will implement actions or perform analyses, as required 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.2.3-1	New fuel additions to the Fire Protection Tank will be analyzed for water and sediment to preclude water contamination, and tank bottoms will be monitored to ensure water or biological activity are not accumulating.
B.2.3-2	The fire protection day tank will be analyzed quarterly for water and sediment, semi-annually for microbiological activity, and will have a one-time boroscope inspection performed.
B.2.5-1(1)	Enhancements to procedures will ensure the diesel fire pump is under direct observation during performance testing.

B.2.5-1(2) The enhancement identified in the license renewal application for Fire Protection Program B.2.5 was to add specific guidance to the halon and fire damper inspection procedures to inspect halon system components and fire dampers for corrosion, mechanical, and physical damage. This enhancement will be implemented prior to the period of extended operation.

B.2.5-1(3) The enhancement identified in the license renewal application for Fire Protection Program B.2.5 was to add specific guidance to the fire door inspection procedures to inspect for wear and missing parts. This enhancement will be implemented prior to the period of extended operation.

Inspection frequencies for fire door clearances will be revised to meet the bimonthly requirement.

B.2.8-1 Visual inspections of the core shrouds at Palisades and FCS in 1995 and 1993, respectively, revealed no panel separation and no missing bolts. Ten-year in-service inspections were performed at FCS in 1992 and will be performed again in 2003 and prior to the period of extended operation. The results of these inspections, the Palisades in-service inspection results, and the results of industry programs will be monitored to determine if additional action, such as ultrasonic inspection, is necessary.

The EPRI MRP is developing an action plan to address potential SCC of reactor vessel internals. OPPD is participating in this program and will take action, as necessary, in response to any recommendations and findings coming from the evaluation.

B.3.1-1(2) An assessment of Alloy 600 and Alloy 82/182 components has been performed and incorporated into the Alloy 600 Program Basis Document. The assessment ... provided conclusions and recommendations to address the specified components...These recommendations will be evaluated as part of the Alloy 600 program and implemented as necessary to ensure the reliability of the Alloy 600 and Alloy 82/182 components.

B.3.1-1(3) The level of detail provided in response to Part 2 of this RAI is not consistent with the level of detail provided in the FCS USAR and will not be included in the USAR supplements. OPPD will incorporate appropriate information from the OPPD responses to GL 97-01 and NRC Bulletins 2001-01, 2002-01, and 2002-02.

B.3.3-5 Procedural guidance is being enhanced as part of the implementation of this new program. Procedures will be revised to include acceptance criteria that a visual indication of loss of material or cracking of elastomer ventilation components identified by the accountable Operator or Engineer will not necessarily lead to an unacceptable component.

B.3.4-1 For non-EQ cables and connections within the scope of license renewal and subject to an aging management review:

1. Prior to the period of extended operation, OPPD will implement a program and inspection consistent with that described in XI.E.1 of the GALL Report.

2. Prior to the period of extended operation, OPPD will implement a program and inspection consistent with that described in XI.E.2 of the GALL Report.

3. ...to ensure that cable susceptible to potentially wetted conditions do not deteriorate, OPPD will implement a program and inspection consistent with that described in XI.E.3 of the GALL.