POI-1

The staff requests that the applicant address the following issues in Section 2.1:

a. During the AMR inspection team's review of the on-site engineering analysis (EA)-FC-00-149, the applicant identified piping systems and associated reference drawings for those systems that have met the 54.4(a)(2) criteria for spatial interaction. The applicant indicated that some of these systems are already within the scope of license renewal but some are not. The applicant also stated that flow accelerated corrosion, chemistry, general corrosion of external surfaces, and structure monitoring program are the applicable AMPs to manage aging effects for components in these systems. On the basis of its review, the staff determined that the information as provided by the applicant is not sufficient for the staff's scoping and aging management reviews for these 10 CFR 54.4(a)(2) SSCs. For the additional SSCs that have been brought into scope to meet the 10 CFR 54.4(a)(2) criterion, the applicant needs to provide scoping information to the component level, equivalent to that of the original license renewal application. This information is necessary for the staff to be able to determine, with reasonable assurance, that all the components required by 10 CFR 54.4(a)(2) to be within the scope of license renewal and subject to an AMR have been correctly identified. Also, the applicant needs to provide revised and/or new Section 2 tables, including links to Section 3 tables, so that the staff may perform an aging management review to determine whether the applicant has identified the proper aging effects for the combination of the material and environment, and has provided an adequate AMP for managing the corresponding aging effects for these SSCs.

Response:

OPPD is basically taking a spaces approach for the aging management of these components. The buildings in which the 10 CFR 54.4(a)(2) criterion applies are the Auxiliary Building, the Intake Structure, and the Diesel Generator Building. These spaces were examined using composite piping drawings for the spaces, isometric drawings for the applicable II/I systems, and walkdowns. The examination evaluated the spaces for the possibility of: 1) physical impact, pipe whip, or jet impingement of safety-related equipment from seismic class II equipment; 2) harsh environments; and 3) leakage or spray onto safety-related electrical equipment. The following steps were taken during the examination:

- The non-safety-related systems with the potential for the adverse spatial interactions identified above with safety-related SSCs were identified using the referenced drawings and walkdowns.
- Based on this determination, applicable aging management programs were identified for these II/I SSCs to manage their aging.
- A review of site operating experience was performed to confirm that the only failures that have occurred relative to any of these II/I systems have been flow

accelerated corrosion (FAC) related failures. Had there been other types of failures, additional screening and aging management review would have been required.

The General Corrosion of External Surfaces Program, the Boric Acid Corrosion Prevention Program (Auxiliary Building only), and the Structures Monitoring Program perform walk downs in the spaces where the II/I Interactions are possible. Any evidence of degradation will be identified, reported via CR, and dealt with through the Corrective Action Program. Additionally, where applicable for the II/I systems, the Chemistry Program, the Flow Accelerated Corrosion (FAC) Program, and the Cooling Water Corrosion Program have also been credited.

Chemistry is a system-based mitigative program that prevents loss of material in those systems where chemistry is maintained. It lends itself readily to the spaces approach of managing the applicable II/I systems.

The FAC Program performs an additional inspection function for loss of material in those high energy systems included in that program. It is a component-based program that looks at the most susceptible locations for that mechanism and provides a bounding approach for the remainder of the system. For this reason, it does not lend itself readily to the spaces approach. Two systems that have been added to the scope of LR for II/I considerations are Auxiliary Steam and Condensate Return. These systems are included in the FAC Program at FCS along with Main Steam, Feedwater, and Steam Generator Blowdown, which were already in scope and managed for FAC.

The Cooling Water Corrosion Program performs an additional inspection function for the Turbine Cooling Water and Demineralized Water Systems. This program includes the identification of the included systems, identification of the potential degradation mechanisms, selection of examination areas, selection of examination methods, examination of the system piping and components, evaluation of the examination results, control of the program data and documentation, and long-term corrosion prevention/mitigation strategies.

New LRA Section 2 tables, with the appropriate links to the LRA Section 3 AMR Tables have been developed to document the results of the 10 CFR 54.4(a)(2) criterion evaluation. Tables 2.3.5-1, -2, and -3 contain the II/I scoping/screening evaluation results for the Auxiliary Building, the Intake Structure, and the Diesel Generator Building, respectively. These tables are included on the following four (4) pages. Even though there is no link provided to the Structures Monitoring Program in these tables, it applies to all SSCs identified in the tables.

Through the use of the spaces approach and the FAC and Cooling Water Corrosion Programs, OPPD will manage aging of the components that have been added to the LR scope to satisfy the 10CFR54.4(a)(2) criterion.

TABLE 2.3.5-1
AUXILIARY BUILDING II/I SYSTEMS
Component Types Subject to Aging Management Review and Intended Functions

Auxiliary Feedwater System		
See Table 2.3.4.2-1, no Component Types added as a result of II/I evaluation		
Auxiliary Steam and Condensate Return Systems		
Component Type	**Intended Function**	**AMR Results**
Piping and Fittings	Seismic II/I	3.4.1.05 3.4.1.06 3.4.1.07 3.4.1.13
Valve Bodies	Seismic II/I	3.4.1.05 3.4.1.06 3.4.1.07 3.4.1.13
Chemical and Volume Control System		
See Table 2.3.3.1-1, no Component Types added as a result of II/I evaluation		
Chemical Feed System		
Component Type	**Intended Function**	**AMR Results**
Piping and Fittings	Seismic II/I	3.4.1.05 3.4.1.02* 3.4.1.13
Valve Bodies	Seismic II/I	3.4.1.05 3.4.1.02* 3.4.1.13
* The One Time Inspection Program does not apply to these components.		
Component Cooling Water System		
See Table 2.3.3.16-1, no Component Types added as a result of II/I evaluation		

TABLE 2.3.5-1 AUXILIARY BUILDING II/I SYSTEMS Component Types Subject to Aging Management Review and Intended Functions		
Demineralized Water		
Component Type	**Intended Function**	**AMR Results**
Piping and Fittings	Seismic II/I	3.3.2.76 3.3.2.75
Valve Bodies	Seismic II/I	3.3.2.76 3.3.2.75
Fire Protection System		
See Table 2.3.3.14-1, no Component Types added as a result of II/I evaluation		
Feedwater System		
See Table 2.3.4.1-1, no Component Types added as a result of II/I evaluation		
Liquid Waste Drain System		
See Table 2.3.3.17-1, no Component Types added as a result of II/I evaluation		
Main Steam System		
See Table 2.3.4.3-1, no Component Types added as a result of II/I evaluation		
Potable Water/Service Water Systems		
Component Type	**Intended Function**	**AMR Results**
Piping and Fittings	Seismic II/I	3.3.1.05* 3.3.1.13 3.3.2.27** 3.3.2.75 3.3.2.76***
Valve Bodies	Seismic II/I	3.3.1.05* 3.3.1.13 3.3.2.27** 3.3.2.75 3.3.2.76***
* The PSPM Program, the Cooling Water Corrosion Program, and the Fire Protection Program do not apply to these components. ** The Cooling Water Corrosion Program and the Fire Protection Program do not apply to these components. *** The Cooling Water Corrosion Program does not apply to these components.		

TABLE 2.3.5-1 AUXILIARY BUILDING II/I SYSTEMS Component Types Subject to Aging Management Review and Intended Functions		
Primary Plant Sampling System		
See Table 2.3.3.19-1, no Component Types added as a result of II/I evaluation		
Raw Water System		
See Table 2.3.3.15-1, no Component Types added as a result of II/I evaluation		
Safety Injection System		
See Table 2.3.2.1-1, no Component Types added as a result of II/I evaluation		
Spent Fuel Cooling System		
See Table 2.3.3.2-1, no Component Types added as a result of II/I evaluation		
Steam Generator Blowdown System		
See Table 2.3.4.1-1, no Component Types added as a result of II/I evaluation		
Turbine Plant Cooling Water System		
Component Type	**Intended Function**	**AMR Results**
Accumulator	Seismic II/I	3.3.1.05* 3.3.1.13 3.3.1.14
Piping and Fittings	Seismic II/I	3.3.1.05* 3.3.1.13 3.3.1.14
Valve Bodies	Seismic II/I	3.3.1.05* 3.3.1.13 3.3.1.14
* The PSPM Program and the Fire Protection Program do not apply to these components.		

TABLE 2.3.5-2 INTAKE STRUCTURE II/I SYSTEMS Component Types Subject to Aging Management Review and Intended Functions
Fire Protection System
See Table 2.3.3.14-1, no Component Types added as a result of II/I evaluation
Raw Water System
See Table 2.3.3.15-1, no Component Types added as a result of II/I evaluation

TABLE 2.3.5-3 DIESEL GENERATOR BUILDING II/I SYSTEMS Component Types Subject to Aging Management Review and Intended Functions
Fire Protection System
See Table 2.3.3.14-1, no Component Types added as a result of II/I evaluation

b. The ATWS Rule (10 CFR 50.62) has the following requirements:

> "(c) Requirements.
>
> (1) Each pressurized water reactor must have equipment from sensor output to final actuation device, that is diverse from the reactor trip system, to automatically initiate the auxiliary (or emergency) feedwater system and initiate a turbine trip under conditions indicative of an ATWS. This equipment must be designed to perform its function in a reliable manner and be independent (from sensor output to the final actuation device) from the existing reactor trip system.
>
> (2) Each pressurized water reactor manufactured by Combustion Engineering or by Babcock and Wilcox must have a diverse scram system from the sensor output to interruption of power to the control rods. This scram system must be designed to perform its function in a reliable manner and be independent from the existing reactor trip system (from sensor output to interruption of power to the control rods)."

The applicant has identified the systems which meet above requirement (c)(2). The applicant has not identified the systems used to meet above requirement (c)(1). In response to RAI 2.1.4-1, the applicant identified the design and installation of the diverse scram system (DSS) as meeting the requirements found in 10 CFR 50.62(c)(1) and (2). As described in the USAR Section 7.2.11, the DSS provides an independent means of initiating a reactor trip. USAR Section 7.2.11 does not identify that the DSS performs the functions required by 10 CFR

50.62(c)(1). The applicant needs to identify which additional systems, if any, are used to meet the requirements of 10 CFR 50.62(c)(1). 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. The information previously provided by the applicant does not specifically address the requirements in 10 CFR 50.62(c)(1). In addition, the applicant made a general comment in the RAI response that:

> "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"

The staff feels that the above statement is not applicable in this case, the reason for the request for additional information was based on 10 CFR 54.4(a)(3) which states that plant systems, structures, and components which meet the following criteria are within the scope of license renewal:

> "(3) 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 fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63)."

The applicant did not identify in the LRA all systems, structures, and components relied on in safety analyses or plant evaluations to demonstrate compliance with 10 CFR 50.62. As a result, the staff needed additional information in order to draw a conclusion that there was reasonable assurance that the applicant has adequately identified the systems and structures within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(3).

Response:

The Diverse Scram System (DSS) performs the turbine trip function as required by 10 CFR 50.62(c)(1). The DSS design description reads,

> *The implementation of a DSS provides an inherent diverse turbine trip. When the DSS causes a reactor trip, it also causes the turbine to trip because the DSS interrupts power to the Control Element Assembly (CEA) coils. The turbine trip is then initiated when clutch power supply relays BW19, BW20, CW19, and CW20 are de-energized. When power is interrupted to the coils the undervoltage relays on the clutch power supplies are de-energized and a turbine trip is initiated. With the implementation of the DSS, the existing turbine trip becomes a diverse turbine trip due to the diversity between the DSS and the existing Reactor Trip System.*

The clutch power relays of the Reactor Protective System (RPS) are the "final actuation device" as specified in 10 CFR 50.62(c)(1).

The DSS also fulfills the requirements of 10 CFR 50.62(c)(2) by performing an independent means of initiating a reactor trip, as described in USAR Section 7.2.11.1.

The Auxiliary Feedwater System (AFW) at FCS is not initiated by the DSS or RPS at FCS. The FCS auxiliary feedwater system is stand alone (i.e., does not rely on DSS or RPS for initiation) in that its initiation devices are completely diverse from the RPS; therefore, the AFW system also meets the intent of 10 CFR 50.62(c)(1). The DS System, Reactor Protective System, and AFW system are the systems at FCS which meet the requirements of 10 CFR 50.62(c)(1) and (2), and are in scope for license renewal. Their SSCs have been screened per NEI 95-10, Rev. 3.

c. The intended functions of a fuse holder are to provide mechanical support for the fuse and to maintain electrical contact with the fuse blades or metal end caps to prevent the disruption of the current path during normal operating conditions when the circuit current is at or below the current rating of the fuse. Fuse holders perform the same primary function as connections, of "providing electrical connections to specified sections of an electrical circuit to deliver rated voltage, current, or signals. These intended functions of fuse holders meet the criteria of 10 CFR 54.4(a). In addition, these intended functions are performed without moving parts or a change in configuration or properties, as described in 10 CFR 54.21(a)(1)(i). The fuse holders into which fuses are placed are typically constructed of blocks of rigid insulating material, such as phenolic resins. Metallic clamps are attached to the blocks to hold each end of the fuse. The clamps can be spring-loaded clips that allow the fuse ferrules or blades to slip in, or they can be bolt lugs to which the fuse ends are bolted. The clamps are typically made of copper.

   Operating experience, as discussed in NUREG-1760, "Aging Assessment of Safety-Related Fuses Used in Low- and Medium-Voltage Applications in Nuclear Power Plants," identified that aging stressors such as vibration, thermal cycling, electrical transients, mechanical stress, fatigue, corrosion, chemical contamination, or oxidation of the connection surfaces, can result in fuse holder failure. The staff requests the applicant to clarify whether fuse holders at FCS are within scope and subject to AMR, or provide justification for their exclusion. The staff also requests the applicant to clarify how fuse holders subject to an AMR will be managed for aging. If additional holders are brought into scope, provide the associated aging management information (material, environment, aging effect(s), and AMPs) so that the staff can determine whether the fuse holders will be adequately managed during the period of extended operation.

Response:

OPPD has included fuse holders in the scope of license renewal as part of the Cable and Connector scoping and screening analysis. There are no fuse holders attached to electrical penetrations at FCS. Fuse holders at FCS that are within active enclosures such as power supplies, switchgear, and Motor Control Centers are considered outside the scope for license renewal. There are no fuse holders at FCS exposed to vibration or environments that would cause corrosion, chemical contamination, or oxidation of the connecting surfaces. Fuse holders within enclosures that are not considered active and subject to mechanical stress, fatigue and electrical transients will be included in the Fatigue-Monitoring Program (B.2.4). OPPD satisfies the technical issues contained in the final issued version of Interim Staff Guidance (ISG) - 5 "On The Identification and Treatment of Electrical Fuse Holders For License Renewal", dated March 4, 2003.

d. During the scoping and screening inspection, the team reviewed engineering analysis (EA)-FC-00-127, "Miscellaneous Systems, Penetrations, and Components," and found that the compressed air, demineralized water, and steam generator feedwater blowdown systems contained components were functionally realigned. The team noted that this was inconsistent with LRA Table 2.2-1 and LRA Section 2.3.2.2. LRA Table 2.2-1 states that containment isolation and/or pressure boundary components in the compressed air, demineralized water, and blowpipe systems were functionally realigned to the commodity group "Containment Penetration and System Interface Components for Non-CQE Related System." However, LRA Section 2.3.2.2, which describes this commodity group, states that the group contains CIVs. It also states that the demineralized water heat exchangers are included in the commodity group to maintain the CCW system pressure boundary. LRA Table 2.2-1 and the description in LRA Section 2.3.2.2 are inconsistent in that the blowdown system is not identified in LRA Table 2.2-1 as having components that were functionally realigned. The applicant should resolve the discrepancies between LRA Table 2.2-1 and the description in LRA Section 2.3.2.2 and provide revised Section 2 tables and, if necessary, Section 3 tables to accurately describe which systems and/or components have been functionally realigned and how the components will be managed.

Response:

The following discrepancies have been noted and corrected as indicated below:

- LRA Table 2.2-1, Item "Steam Generator Feedwater Blowdown" has been changed to "Steam Generator Blowdown" and a link to Footnote 1 has been added in order to correctly identify this system as part of the Containment Penetration and System Interface Components for Non-CQE Related System analysis.
- The first sentence in LRA Section 2.3.2.2 has been revised to read "...includes the containment isolation valves of the Steam Generator Blowdown, Compressed Air, Blowpipe, and Demineralized Water Systems..." in order to correctly identify the steam generator blowdown system. The steam generator blowdown system has always been included in the LRA; however, the word 'Feedwater' was

inadvertently included in the title of the system because it was included in the title of the drawing used to depict the system boundary.

- The Blowpipe system is correctly identified in the LRA; however, the boundary drawing for the system (which only consists of a containment penetration blanked off on both ends) was not included with the original LRA submittal. This drawing, 11405-M-1, Sheet 2, Containment Heating, Cooling & Ventilation Flow Diagram P&ID, has been provided by the Reference 3 letter. The only function of the "Blowpipe" system is to provide compressed air during the Containment Integrated Leak Rate Test. At all other times, this penetration is blanked off. The material/environment is the same as shown in LRA Table 2.3.2.2-1 for Component Types "Primary Containment Penetrations" and "Bolting" with the same AMPs.

POI-2

The staff requests that the applicant address the following issues in LRA Section 2.3.1:

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, cracking and/or wall thinning, which can cause the flow area to increase during the period of extended operation. Accordingly, in RAI 2.3.1.2-3, the staff requested 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.

In response, the applicant stated that the FCS flow limiters are of the venturi type, and are fabricated of Inconel. They are built into the piping downstream of the first elbow in the horizontal main steam system piping runs leaving the steam generators. For license renewal, 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 of the LRA, main steam and turbine steam extraction, under the component type "Pipes & Fittings." The applicant further stated that 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. As a result, the applicant agreed to add "Flow Restriction" as a license renewal intended function in Table 2.3.4.3-1 of the LRA. The applicant, however, concluded that since the venturi is fabricated of Inconel, there is no plausible aging related degradation in the secondary side steam flow environment, and as a result, there is no AMP needed to manage the venturi throat diameter. The applicant should submit the revised Table 2.3.4.3-1 of the LRA showing "Flow Restriction" as an intended function to be maintained during the period of extended operation, and provide a corresponding link in the table. The link should take the reader to an appropriate sub-section within Section 3 of the LRA, "Aging Management Review," for a discussion as to why the applicant believes that no AMP is required.

Response:

Please see Appendix A to this response letter for the revised LRA Tables. Table 2.3.4.3-1 now shows that "Flow Restriction" is an intended function under "Piping and Fittings." For components that do not have an AERM, the LR Rule does not require the applicant to provide specific discussion within the application for each of these components as to why the component does not have an AERM or why an AMP is not required. In this case, the only aging effect that would be considered is loss of material due to flow-accelerated corrosion; however, because this mechanism only occurs in carbon steel applications, it is not an AERM for Inconel and an AMP is therefore not required.

POI-3

The staff requests that the applicant address the following issues in LRA Section 2.3.3:

a. By letter dated October 11, 2002, the staff requested the applicant to justify the location of the license renewal boundaries (piping connected to a portion of the raw water system discharge header piping passing through the auxiliary building and turbine building) located at design class boundaries, but do not coincide with isolation valve locations, with regard to protection of essential systems from internal flooding in the event of failure of the pressure boundary of the non-safety related piping outside of the license renewal scope boundary (RAI 2.3.3.15-1).

   By letter dated November 22, 2002, the applicant responded to this request by stating that an engineering analysis and a calculation have demonstrated that the design class boundaries are acceptable at a non-valve location. This analysis determined that internal flooding of the turbine building due to failure of the piping will not affect any safe shutdown equipment nor will floods propagate from the turbine building to the auxiliary building. Additionally, the analysis showed that the floor drains in the auxiliary building can easily handle a postulated flood resulting from rupture of any of the lines that tie into the backup raw water header in the auxiliary building. Section 2.3.3.17 of the LRA states that the auxiliary building floor drains perform an intended function for flood mitigation and referenced drawings show that the floor drains are within the license renewal scope boundaries. Finally, the analysis determined that a postulated break in any of the non-safety related piping in question would not impair the ability of the raw water system to perform its intended safety function.

   The staff evaluated the above information. The staff concluded that there is reasonable assurance that the failure of the pressure boundary of the non-safety related piping outside of the license renewal scope boundary would not affect equipment necessary for safe shutdown or for mitigation of design basis events through flooding. However, during evaluation of this information, the staff noted that Section 2.3.3.15 of the LRA describes the raw water discharge from the component cooling water heat exchangers and the discharge from the direct cooling raw water header flow into the circulating water discharge tunnel. Table 2.2-1 of the LRA designated the circulating water system as outside of license renewal scope without specific justification, but failure of the pressure boundary of buried piping or tunnels creates the potential for a loss of flow. Therefore, the location of the license renewal boundary at the discharge pipes for the raw water system rather than at the outlet from the circulating water discharge tunnel has not been adequately justified. On the basis of the above discussion, the applicant should provide justification for the location of the license renewal boundary.

Response:

The location for the raw water discharge license renewal boundary at check valves CW-188 and CW-189, upstream of the circulating water discharge tunnel, has been revised based on the following discussion:

1) The circulating water discharge tunnel is constructed of reinforced concrete with a nominal wall thickness of 2' or greater and nominal floor/ceiling thicknesses of 2'-6" or greater throughout. The concrete circulating water discharge tunnel walls, floor and ceiling are constructed of Type B concrete in accordance with ACI 201.2R as specified in NUREG-1557.

2) The concrete is not exposed to aggressive river water or groundwater. The concrete that surrounds the embedded steel has a pH greater than or equal to 12.5. The concrete mix design specified a water-to-cement ratio of 0.44 and air entrainment of 5.00% + 1.00% for Class B concrete. The concrete at FCS was designed in accordance with ACI 318-63 (per USAR Section 5.3.1 Revision 0 and USAR Section 5.11.3.1 Revision 2).

3) The maximum flow rate in the circulating water tunnel is well below the velocity of 25 fps required to initiate abrasion. The calculated highest water velocity for a closed conduit is in the warm water recirculating tunnel at 12.6 fps. Therefore, this aging effect is not credible.

4) Per NUREG-1557, corrosion of embedded steel is not significant for concrete structures above or below grade that are exposed to a non-aggressive environment. A non-aggressive environment, as defined by NUREG-1557, is one with a pH greater than 11.5 or chlorides less than 500 ppm. NUREG-1557 also concludes that corrosion of embedded steel is not significant for concrete structures exposed to an aggressive environment but having a low water-to-cement ratio, adequate air entrainment, and designed in accordance with ACI 318-63 or ACI 349-85. A low water-to-cement ratio is defined as 0.35 to 0.45 and adequate air entrainment is defined as 3 to 6 percent. Therefore, corrosion of embedded steel is not credible.

5) The freeze/thaw exposure category is "Severe" since the concrete of concern is in direct contact with the soil. Based on recent analyses, the groundwater and river water contain minimal amounts of chlorides (8.0 ppm and 14.0 ppm respectively),

sulfates (79 ppm and 229 ppm respectively), and the pH is slightly alkaline (7.48 and 8.39 respectively); therefore, the exposure category for sulfates, chlorides, and acids is "Mild", and concrete degradation is not credible for the circulating water discharge tunnel.

6) The total flow of the raw water equates to less than 5% of the total volume of the circulating water discharge tunnel.

As noted above, conditions specified in NUREG-1557 have been satisfied; therefore, minimal or no aging effects will be realized in the circulating water discharge tunnel. Tunnel failure will not occur to the point that the raw water intended function would be impacted or jeopardized during the period of extended operation. To verify this assumption, OPPD will perform a One Time Inspection of the circulating water discharge tunnel per the One Time Inspection Program (B.3.5). The circulating water discharge tunnel will be included in scope for license renewal as part of the Intake Structure. Please refer to LRA Table 2.4.2.3-1, Intake Structure, Component Types "Carbon Steel Pipe Sleeve and Flange Floor Penetration," "Concrete Below Grade," and "Concrete Exposed to Raw Water." Revised boundary drawing 11405-M-100 and new boundary drawing 11405-M-257, Sheet 2 showing the circulating water discharge tunnel in scope for license renewal have been provided by the Reference 3 letter.

b. NRC Inspection Report 50-285/02-07, which focused on the scoping and screening process at FCS for license renewal, identified Open Item 50-285/02-07-01 related to the CCW system pressure boundary for the safety injection tank leakage cooler subsystem. Boundary Drawing 11405-M-40, Sheet 3, indicated that the safety injection tank leakage cooler subsystem was excluded from the scope of license renewal. This included the four coolers, associated piping, valves, and instrumentation. Component cooling water is supplied to the four leakage coolers via 3-inch piping at approximately 300 gpm. Component cooling water will automatically isolate on a containment isolation signal. The inspectors asked what affect a pipe break, in this non-safety related subsystem, would have on the component cooling water system. The applicant stated that if leakage were to occur, it would be noticed in the containment sump coupled with a change in flow that would be sensed by flow elements downstream of the coolers. However, due to the size of the containment sump, leakage may not be immediately noticed. Additionally, neither the flow indicators nor the flow elements were included within scope of the Rule. The applicant has not submitted sufficient information to demonstrate that loss of pressure boundary integrity within this non-safety related subsystem would not prevent completion of the intended functions of the CCW system and, therefore, the subsystem could be excluded from the scope of license renewal in accordance with 10 CFR 54.4.

Response:

The portion of CCW that provides cooling to the SI Leakage Coolers is included within scope of License Renewal. The piping and components will be added to the License Renewal database and the CCW AMR evaluation will be revised to include these components prior to issuance of the SER. LRA Table 2.3.3.16-1 component types "Heat Exchanger," "Pipes and Fittings," and "Valve Bodies" include all of the added components (see Appendix A to this letter). Revised drawing 11405-M-40 Sheet 3 has been provided by the Reference 3 letter.

c. The applicant provided the proprietary vendor drawings showing the interior of the three equipment cabinets on drawing 11405-M-1, Sheet 2 in response to RAI 2.3.3.20-1. Upon review of those drawings, the staff has the following questions.

1. On all three of the vendor drawings, the license renewal boundaries end in the middle of pipes with no physical means of isolation. Justify placing the boundaries at these locations.

2. The housings for the following gas samplers: RE-052, RM-062, and RE-051 are within the scope of license renewal but are not listed in LRA Table 2.3.3.20-1. These housings appear to perform a pressure boundary and/or fission product retention function. Therefore, these 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 gas samplers housings subject to an AMR.

Response:

1) The boundaries for each of the radiation monitors have been evaluated and revised accordingly. For radiation monitoring cabinet (RMC) AI-80, the boundary is now located at isolation valves VA-413 and VA-414 of the containment ventilation system (VA-CON). For RMC AI-81 the boundary is located at VA-1189, -1190, -1191, and -1192 of the VA-CON system. For RMC AI-83 the boundary has been taken all the way out to the ventilation stack. These changes have been made to the following drawings which have been provided by the Reference 3 letter: 11405-M-1, Sheet 2; 703741-00 (AI-80); 800997-001(AI-81); and 801104-001(AI-83). This change to the boundaries did not bring any new components into scope for this system. However, a new component type "Pressure Vessel" was added to clarify the gas sampler's construction (see below).

2) Component RE-052 is actually a gas detector and is considered an active component and not subject to AMR. Component RM-062(-S) is a gas sampler and has been included in a new component type "Pressure Vessel," with an Intended Function of "Pressure Boundary/Fission Product Retention" and is linked to LRA AMR Table 3.3.2.75. This component type has been added to LRA Table 2.3.3.20-1. Component RE-051 is a gas detector similar to RE-052 and is also considered an active component. Gas samplers RM-052-S and RM-051-S have also been included in component type "Pressure Vessel." The revised LRA Table 2.3.3.20-1 is included in Appendix A to this response letter.

POI-4

The staff requests that the applicant address the following issue in LRA Section 2.3.4:

There are numerous pressure and level transmitters highlighted on drawing 11405-M-253, Sheet 1. From the drawing, it appears the instrument housings form part of a pressure boundary with their associated piping. While the instruments themselves may not be subject to an AMR, 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 if they perform a pressure boundary function. In its response to RAI 2.3.4.1-1, the applicant did not address the instrument housings. Justify not making the instrument housings subject to an AMR.

Response:

OPPD has included all pressure boundaries associated with instruments within scope, in accordance with NEI 95-10, and subjected them to an AMR.

POI-5

The staff requests that the applicant address the following issues in LRA Section 2.4:

a. In response to RAI 2.4.1-2, the applicant stated that the airlock seal is periodically replaced and is not subject to an AMR. The applicant needs to provide information on (1) how often the airlock seal is replaced, (2) how often the airlock seal is inspected, and (3) provide a discussion on the program that's used to maintain the airlock seal.

Response:

Gaskets, O-rings and the like are considered consumables and are not subject to AMR as per NEI-95-10, Rev. 3. These particular gaskets (seals) are replaced periodically as described below.

The Periodic Surveillance and Preventive Maintenance Program (PS&PM) performs a periodic inspection and maintenance of Containment Personnel Air Lock (PAL) AE-2. The procedure is performed on one door (alternating between the inner/outer door) each refueling outage. The applicable (inner or outer) door is inspected and the seals replaced during each performance of the PS&PM procedure.

b. In a letter dated December 19, 2002, in response to RAI 2.4.2.5-1, the applicant stated that since the aging management of cranes is consistent with the NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," which does not provide a detailed listing of crane/lifting device subcomponents, OPPD did not deem it necessary to list subcomponents in LRA Table 2.4.2.5-1. The GALL report does not address scoping of structures and components for license renewal. Scoping is plant specific, and the results depend on plant design and current licensing basis. The GALL report states that "the inclusion of a certain structure or component in the GALL report does not mean that the particular structure or component is within the scope of license renewal for all plants. Conversely, the omission of a certain structure or component in the GALL report does not mean that the particular structure or component is not within the scope of license renewal for any plants." In essence, the GALL report is not applicable to plant scoping for license renewal, although, certain structures and components evaluated within the GALL report may be within the scope of license renewal for a specific plant.

The applicant's letter of December 19, 2002, in response to RAI 2.4.2.5-1, did not identify and list the structures and components subject to an AMR in accordance with 10 CFR 54.21(a)(1). Therefore, the SCs for the fuel handling equipment and heavy load cranes have not been identified and listed in Table 2.4.2.5-1 in such manner as to allow the staff to determine, with reasonable assurance, that all of the SCs have been included within the scope of license renewal. The staff requests the applicant to provide a list of these SCs for the fuel handling equipment and heavy load cranes.

Response:

The last paragraph of the response to RAI 2.4.2.5-1 includes the subcomponent breakdown that was used for FCS scoping/screening. As clarification, each one of these cranes, lifting rigs, etc., includes the entire device from the lifting apparatus to the structural supports used to mount the crane to the structure in which it is mounted. The mounting bolting is included in the Component Supports Commodity.

c. In its letter dated December 19, 2002, the applicant provided its response to RAI 2.4.2.5-2. In RAI 2.4.2.5-2, the staff stated that the boral panels protected with stainless steel, that are attached to the spent fuel pool storage racks, support the prevention of criticality in the spent fuel pool. As such, they perform an intended function of preventing criticality and they should be included within the scope of license renewal and subject to an AMR. In addition, LRA Table 2.4.2.5-1 should be revised to include the boral panels and their stainless steel covering. The applicant, in the RAI response, indicated that the boral panels have been included in LRA Table 2.4.2.1-1, "Auxiliary Building," with the component type "Spent Fuel Storage Racks," and are managed for aging following item 3.3.1.09 of the LRA. The staff reviewed Table 2.4.2.1-1 and did not find the component type of spent fuel storage racks listed in the table. The applicant should provide a revised LRA Table 2.4.2.1-1, including link 3.3.1.09.

Response:

OPPD erred in the response to RAI 2.4.2.5-2. The reference to Table 2.4.2.1-1, Auxiliary Building, should have been written as Table 2.4.2.5-1, Fuel Handling Equipment and Heavy Load Cranes. In that table, the Component Type "Spent Fuel Storage Racks" is linked to AMR Item 3.3.1.09 which applies to "Neutron absorbing sheets in spent fuel storage racks" and the Aging Effect/Mechanism is identified as being applicable to Boral and boron steel.

POI-6

The staff requests that the applicant address the following issues in LRA Section 2.5:

a. By letter dated October 11, 2002, the staff issued RAI 2.5-1, requesting the applicant to identify the applicable offsite power SSCs within the scope of license renewal and subject to an AMR as a result of meeting the 10 CFR 54.4(a)(3) scoping criterion for SBO. By letter dated December 19, 2003, the applicant responded to the RAI. The applicant's aging management review results for the electrical components for external environments are shown in Table 2 of the applicant's response. This table also refers to FCS-specific programs that have been credited for aging management of SBO restoration system components. However, several SBO components (high-voltage bus work/duct, aluminum conductor, steel reinforced (ACSR) transmission cables and insulators associated with the transmission conductors) are not identified in Table 2 as requiring an AMR. The staff believes that these components meet the SBO scoping criterion and are passive and long-lived, as are the surge arrestors. Therefore, the staff requests the applicant to clarify whether these components are within scope and subject to an AMR, or justify their exclusion. If these components are within scope, provide the associated aging management information to allow the staff to determine whether the components will be adequately managed during the period of extended operation. In addition, it is not clear to the staff why the 125 vdc and (120 vac) control and instrumentation cables associated with the SBO restoration system components are not included in the table. The applicant should clarify whether these components are subject to an AMR and provide the associated aging management information.

Response:

The high-voltage aluminum conductor is steel reinforced (ACSR) transmission cable and is considered in the scope of License Renewal for Station Blackout (SBO). In accordance with EPRI TR-114882, Non-Class1 Mechanical Implementation Guideline and Mechanical Tools, Revision 2, 1999, no aging effects were identified for aluminum, aluminum alloys, copper, or copper alloys (brass, bronze) in an indoor or outdoor air environment. Transmission conductor vibration would be caused by wind loading. Wind loading that can cause a transmission line and insulators to vibrate is considered in the design and installation. Loss of material (wear) and fatigue that could be caused by transmission conductor vibration or sway are not aging effects requiring management for the period of extended operation for Fort Calhoun. A review of internal and external operating experience has not identified any aging unique effects requiring management.

The insulators associated with the transmission conductors are made of porcelain and are within the scope of license renewal. Aging effects that are considered are buildup of surface contaminants and loss of material due to vibration (wear). As indicated above (transmission line vibration), vibration due to wind loading is a design consideration and not considered an aging affect requiring management. Buildup of surface contaminants i.e. dust, dirt, etc. can occur, however, it is gradual and frequently washed away by rain, consequently the buildup of surface contaminants is not significant and therefore not an aging effect requiring management at Fort Calhoun. Information Notices applicable to insulator contamination (IN-93-95) relate to a loss of power due to salt buildup. Fort Calhoun is not located in an area of any salt concentration (Nebraska) and, therefore does not consider this IN applicable. On the basis of the above, It has been determined that the porcelain insulators in outside air, at Fort Calhoun, is not subject to any aging effects requiring management.

The arresters associated with the offsite power system, although within the SBO boundary, do not have any intended functions associated with license renewal, and are eliminated from the scope of license renewal as active components in accordance with NEI-95-10.

The isolated phase bus duct (i.e., isophase or 22KV bus duct) encloses buswork that connects the Main Generator output to the Main Transformer. It is not related to the underground bus duct that may carry low voltage power, control, and instrumentation wiring. The buswork is treated in 6b below and has no AERM. The enclosure supports for the isophase bus are identified in the LRA and assigned to the Structures Monitoring Program for external environment. There is no AERM for internal environment.

The 125-volt dc and 120 volt ac control and instrumentation cables associated with breaker controls and instrumentation within the SBO Restoration System have been considered in the scope of License Renewal for SBO. Under Non-EQ cables, all cables are subject to the Non-EQ cable AMR. All Non-EQ cable was identified in, and managed by, the Non-EQ Cable Aging Management Program (B.3.4). Please see LRA Table 2.5.1-1, Cables and Connectors. As discussed above, the high-voltage aluminum conductors were additionally identified to complete the scope change required by considering the switchyard equipment in scope for License Renewal for SBO.

The electrical equipment (i.e., breakers, relays, etc.) was considered as within scope of license renewal and has been eliminated from AMR consideration, based on NEI-95-10, as active equipment.

Please see new LRA Table 2.5.21-1, Substation-Station Blackout Restoration below, for component types subject to AMR.

TABLE 2.5.21-1
SUBSTATION-STATION BLACKOUT RESTORATION
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	Aging Management Review Results
161 kV Deadend Towers	Structural Support	3.5.1.25
161 kV Line Carrier Equipment	Structural Support	3.5.1.25
22 kV Bus Duct	Shelter/Protection	3.3.2.23

Component Type	Intended Functions	Aging Management Review Results
		3.5.1.25
345 kV Line Carrier Equipment	Structural Support	3.5.1.25
Bolting	Structural Support	3.5.1.25
Circuit Breaker Electrical Enclosures	Structural Support Shelter/Protection	3.5.1.25
Concrete Pads and Foundations Below Grade	Structural Support	3.5.1.09
Concrete Pads and Foundations In Outside Air	Structural Support	3.5.1.09
Galvanized Steel Supports	Structural Support	3.5.1.25
High Voltage Conductors	Electrical Continuity	No aging effects requiring management were identified for this component
Non-EQ Cables	Electrical Continuity	3.6.1.02
Structural Steel ISO Phase Bus	Structural Support	3.5.1.25

b. In LRA Table 2.5.20-1, the applicant identifies electrical bus bars and bus bar standoffs as components that are within the scope of license renewal and subject to an AMR. Table 2.5.20-1 also states that these components have no aging effects requiring management. The basis for the applicant's conclusion is unclear to the staff. The applicant should provide information on the component materials and environments, along with the basis for concluding that these components have no aging effects requiring management.

Response:

The bus bar materials are copper and aluminum; their environment is in indoor air and outdoor air. In accordance with EPRI TR-114882, Non-Class1 Mechanical Implementation Guideline and Mechanical Tools, Revision 2, 1999, no aging effects were identified for aluminum, aluminum alloys, copper, or copper alloys (brass, bronze) in an indoor or outdoor air environment.

The stand offs include fiberglass reinforced polyester resin and porcelain materials that are in ambient air external environment and are not continuously wetted. Internal environments are not applicable.

Table 7-17 of EPRI NP-1558, A Review of Equipment Aging Theory and Technology lists the continuous use temperature of plastics. The continuous use temperature[(a)] listed for polyester with 40% glass content is 266 degrees F[(b)] (compared with the bounding temperature value of 122 degrees F). Applying the Arrhenius methodology, it is clear that fiberglass reinforced polyester is acceptable. Figure C-2 of EPRI NP-1558 contains the relative radiation stability of thermosetting resins. The threshold for gamma radiation for polyester (glass filled) is 1,000,000,000 Rads (compared with the bounding 60-year radiation dose of less than 1,000 Rads).

Based on a review of the materials of construction and operating environments, there are no applicable aging affects for these materials.

The justification for the bus bar and the stand off materials not requiring aging management was presented in the electrical bus bar aging management review, and is maintained in onsite documentation for review.

(a) Continuous use temperatures were determined as the temperatures corresponding to 100,000 hours (11.4 years) on the Arrhenius curve of the material for an endpoint of 50% reduction in tensile strength.

(b) Based on retention of tensile strength taken at 500 degrees F.

POI-7

The staff requests that the applicant address the following issues in LRA Appendix B:

a. In its response to RAI B.1.1-1, the applicant did not state why stress corrosion cracking (SCC) regarding high-strength carbon steel bolting in plant indoor air is not an aging factor and does not require a management program. The applicant should provide justification to the exception to GALL. Specifically, the applicant should provide justification for why SCC in high-strength carbon steel bolting in plant indoor air is not a credible aging effect, and why an ASME Section XI, Subsection IWF visual VT-3 inspection is adequate to inspect supports rather than volumetric inspections?

Response:

The justification for why CS bolting is not susceptible to SCC was included in the response to RAI 3.2.1-2. Additionally, the high strength bolting material at FCS is not A490 (with the exception of embedded bolts for the steam generator supports) and is not in an environment that would cause this AERM.

b. With regard to the containment inservice inspection program (B.1.3), for inspection of concrete components of the FCS containment, the applicant is committing to use GALL Program XI.S2, "ASME Section XI, Subsection IWL" during the period of extended operation. The GALL program recognizes the absence of explicit acceptance criteria for concrete components (in Element 6, Acceptance Criteria), and recommends the use of Chapter 5 of ACI 349.3R. The applicant is requested to provide information regarding the acceptance criteria to be used for examination of containment concrete at FCS.

Response:

The FCS Containment ISI Program meets the requirements of ASME Section XI, Subsection IWL, and is consistent with the criteria specified in GALL program XI.S2, "ASME Section XI, Subsection IWL". Per NRC request, a copy of the vendor procedure used for the ASME XI, Subsection IWL, inspection performed in 2001 is provided as Appendix B of this submittal.

c. The staff asked several RAIs related to the aging management of the fire protection fuel oil storage tank and its associated piping and fittings. RAI 3.3.2-3 related to how the diesel fuel monitoring and storage program (B.2.3), which focuses on internal oil environments, would be used to monitor for the external corrosion of the carbon steel and galvanized steel piping and fittings and the copper-zinc alloy tubing, that are exposed to an above-ground, buried in gravel (and protected from the elements) environment. RAI B.2.3-1 relates to an exception that the diesel fuel monitoring and storage program takes to GALL Program XI.M30, "Fuel Oil Chemistry," where the applicant proposes to use leakage detection in lieu of ultrasonic testing on the fire protection diesel fuel tank due to inaccessibility. In its December 19, 2002, responses to these RAIs, the applicant continues to rely on leakage detection to monitor for internal and external corrosion of the fire protection diesel fuel tank and the associated piping. The LRA states that the diesel fuel monitoring and storage program will be enhanced to add the removal of sediment and water from the bottom of the fire protection diesel fuel tank, which indicates that this has not historically been performed. The current condition of the tank is unknown, and the staff does not consider leakage detection to be effective aging management for internal and external corrosion of the tank, pipes, fittings, and tubing.

1. Provide additional information on the current condition of the tank and associated piping and fittings to justify that the condition of this tank is comparable to other fuel oil storage tanks.

2. The December 19, 2002, response to RAI B.2.3-1 states that inspections are performed on other diesel fuel storage tanks. Explain why the inspections of other tanks would be leading indicators of degradation of the fire protection diesel fuel oil tank considering that the oil in the fire protection diesel fuel oil tank has not been maintained to the same standards (as implied by the LRA statements that actions would be <u>added</u> to remove water and sediment from the bottom of the tank).

3. Explain why boroscopes or other instruments cannot be used to evaluate the condition of the tank internals and piping internals.

4. Describe any measures that have been taken to maintain the tank and piping externals in a benign environment, thereby minimizing the potential for loss of material.

Response:

In lieu of answering the above requests, OPPD commits to performance of a one-time inspection prior to the period of extended operation to determine the condition of the fire protection fuel oil tank and verify it is not in a degraded condition.

d. 1. In response to RAI B.2.9-2, the applicant indicates that the secondary shell, secondary handholds, secondary head, secondary manway, and transitional cone 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.

The applicant stated that Class C Cleanliness Standards, required for the secondary side indicate that; "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."

The applicant's RAI response does not include sufficient detail for the staff to determine whether the proposed inspection will provide reasonable assurance that this aging effect will be adequately managed during the period of extended operation. 1) The applicant states that at least one of these components is "representatively" visually inspected each refueling outage. Explain what "representatively" means in this context and the basis for the appropriateness of this level of inspection (i.e., sample size). 2) In order to detect pitting and crevice corrosion, the visual inspection must be performed in accordance with specified requirements (e.g., ASME Code VT-1). Describe the method or technique (including codes and standards) used to perform the visual inspection. 3) The applicant should specify the acceptance requirements utilized to analyze the condition of the component once a condition report is initiated which ensures that the structure and component intended function(s) are maintained under all CLB design conditions during the period of extended operation.

Response:

1) Representatively implies that the item inspected bounds items that are not inspected. The manways and handholds are visually inspected each time. Since these components are all low-alloy steel in a deoxygenated treated water environment, and there is no site or industry experience with significant degradation to these components, then the inspection of the internal surfaces of the manways and handholds are representative of the other non-inspected items. A detailed crawl-through of the steam generator secondary side occurs and allows observation of other internal surfaces as well.

2, 3) There is no specific industry standard for acceptance criteria established for visual inspections of the secondary side pressure boundary surfaces. The condition of the secondary side steam generator components is considered acceptable if the knowledgeable personnel responsible for the performance of the inspections determine that there is no evidence of damage or degradation sufficient to warrant further evaluation or performance of repair/replacement activities. Although inspections are not required to be performed in accordance with ASME VT-1 requirements, inspections are overseen by Quality Control personnel who are VT-1 qualified. OPPD continues to perform these secondary side pressure boundary inspections as presented in OPPD's response to GL 97-06, dated March 25, 1998. In the NRC closeout of that response, dated September 29, 1999, the staff found these inspection practices provided reasonable assurance that the steam generator internals are in compliance with the current licensing basis. NUREG/CR-6754 concluded that there are no near-term problems nor are there needs for any immediate change in the current SG internals inspections. Furthermore, these same components are inspected for loss of corrosion at the weld locations by ultrasonic testing by the Inservice Inspection Program. Since there is no site or industry experience with significant pressure boundary degradation, OPPD considers these inspections as adequate aging management for the period of extended operation.

2. Loss of section thickness due to flow-accelerated corrosion in tube support lattice bars made of carbon steel is managed by the steam generator program. In response to RAI B.2.9-2, the applicant indicates that tube supports (batwings, eggcrates, and vertical grids) are visually inspected for loss of material (flow-accelerated corrosion, general, pitting, crevice, and galvanic corrosion). A portion of the batwings are inspected each refueling outage. In addition, 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, eddy current testing (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.

The applicant's RAI response does not include sufficient detail for the staff to determine whether the proposed inspection will provide reasonable assurance that this aging effect will be adequately managed during the period of extended operation. 1) The applicant indicates that tube supports (batwings, eggcrates, and vertical grids) are visually inspected for loss of material (flow-accelerated corrosion, general, pitting, crevice, and galvanic corrosion), and that a portion of the batwings are inspected each refueling outage. It is not clear to the staff exactly what components (batwings, eggcrates and/or vertical grids) are inspected each refueling outage, the inspection method (i.e., visual and/or eddy current testing) of each sample, the sample size, and the applicant's basis for the inspection population and sample size. 2) The applicant did not describe the method or technique (including codes and standards) used for the visual inspection. 3) The applicant should specify the acceptance requirements utilized to analyze the condition of the component based on the inspection results.

Response:

1) The inspection includes visible tube support structures as seen on a detailed crawl-through of the steam generator secondary side. Visible tube support structures include visible portions of the vertical and diagonal supports protruding from the top of the tube bundle, the periphery of the # 8 tube support plates and small portions of the periphery of the # 7 eggcrate support. Also included are portions of the supports which are visible through the handholes. The results are documented in the inspection procedure and in photographs taken during the inspection with standard and macro-capable photographic equipment.

2) The method and technique were described. There are no specific industry codes and standards for the visual examination of these secondary side internals. Eddy-current testing of the tubes is performed per technical specifications and NEI 97-06 guidance documents.

3) There is no specific industry standard for acceptance criteria established for visual inspections of the secondary side pressure boundary surfaces The condition of the secondary side steam generator components is considered acceptable if the knowledgeable personnel responsible for the performance of the inspections determines that there is no evidence of damage or degradation sufficient to warrant further evaluation or performance of repair/replacement activities. The Combustion Engineering Owners Group (CEOG) Evaluation of Degraded

Secondary Internals Operability Assessment, (performed as an industry response to GL 97-06), concluded that even those plants which had experienced degradation of tube supports could continue to operate safely because there was adequate margins against tube damage and the damage could be detected in the normal eddy current examinations. Therefore the detection level is not an issue. Furthermore, the CEOG evaluation concludes that this damage mechanism only occurs when there is fouling sufficient to redistribute the flow to the periphery of the bundle. No steam pressure loss has been noted at FCS which would be apparent if fouling were occurring at a level sufficient to redistribute the flow. These tube support inspections were presented in OPPD's response to GL 97-06, dated March 25, 1998. In the NRC closeout of that response, dated September 29, 1999, the staff found the inspection practices provided reasonable assurance that the steam generator internals are in compliance with the current licensing basis. Furthermore, since site operating experience has not found flow-accelerated corrosion in the supports, OPPD concludes that these inspections are adequate aging management.

3. The applicant states that ligament cracking due to corrosion could occur in carbon steel components in the steam generator tube support plate is managed by the steam generator (B.2.9) and chemistry (B.1.2) programs. The staff's review of the steam generator program (B.2.9) is discussed here. In response to RAI B.2.9-2, the applicant indicates that tube supports (batwing, eggcrates, and vertical grids) are visually inspected for loss of material (flow accelerated corrosion, general, pitting, crevice, and galvanic corrosion). The applicant does not describe the inspections, sample size, and acceptance criteria implemented to detect the presence of ligament cracking. The applicant should specify these requirements.

Response:

Cracking was inadvertently left off the list when the revised RAI response was submitted. See response to POI-7.d.3 above for discussion of the inspections sample size. There is no industry acceptance criteria related to detecting the presence of ligament cracking on support plates. Although minor cracking has occurred in the upper most tube support plates, this cracking was the result of stresses being relieved after a rim cut modification to allow expansion of the plates. As stated in NUREG/CR-6754, the rim cut modification was a proactive measure to minimize the possibility of denting and delaying the onset of ligament cracking. The Combustion Engineering Owners Group (CEOG) Evaluation of Degraded Secondary Internals Operability Assessment concluded that support plate cracking is not detrimental to the safe operation of the plant and there are no reported tube wear indications directly related to tube support degradation. Therefore, the level of detectability of cracks is not an industry issue. Furthermore, these tube support inspections were presented in OPPD's response to GL 97-06, dated March 25, 1998, and the staff found the inspection practices provided reasonable assurance that the steam generator internals are in compliance with the current licensing basis. Therefore, OPPD concludes that management of aging is adequate for this aging mechanism.

4. In response to RAI B.2.9-2, the applicant described the inspection program related to nozzles, nozzle safe ends and the feedring (i.e., steam generator feedwater, steam and instrument nozzles, steam and feedwater nozzle safe ends, and the steam generator feedring) as follows: the applicant indicated that 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. Site Class Cleanliness Standards 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.

   The applicant's RAI response does not include sufficient detail for the staff to determine whether the proposed inspection will provide reasonable assurance that this aging effect will be adequately managed during the period of extended operation. 1) The applicant states that 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. The applicant should provide the basis for the statement that the carbon steel feedring is more susceptible to aging than the carbon steel nozzles and nozzle safe ends. 2) The applicant states that the external surface of the feedring is visually inspected each refueling outage for corrosion, but does not indicate the extent of the feedring that is inspected, nor the basis for this extent. 3) The visual inspection must be performed in accordance with specified requirements (e.g., ASME Code VT-1). Describe the method or technique (including codes and standards) used to perform the visual inspection. 4) The applicant should specify the acceptance requirements utilized to analyze the condition of the component once a condition report is initiated which ensures that the structure and component intended function(s) are maintained under all CLB design conditions during the period of extended operation.

Response:

1) The nozzles, nozzle safe ends and feedring are all in the same environment of deoxygenated treated water >200°F. The carbon steel feedring is more susceptible to corroding than low-alloy steel nozzles and nozzle safe ends, and therefore is bounding. The carbon steel feedring is equally susceptible to corroding as the carbon steel nozzles and nozzle safe ends. Furthermore the material of the feedring is thinner than the thickness of the nozzles and nozzle safe ends.

2) The visible portions of the feedring inspected include almost the entire feedring, excluding the underside. The basis of this extent is accessibility.

3) See POI-7.d.3 above for discussion regarding ASME Code VT-1. There are no codes and standards for performing this visual inspection.

4) Once a Condition Report is written, the site Corrective Action Program provides the means of review, evaluation, and corrective action. The results of evaluations determine the acceptance criteria and may be based on many variables.

5. In response to RAI B.2.9-2, the applicant described the inspection program related to the secondary-side tubesheet as follows: The secondary side tubesheet is visually inspected and supplemented by tube eddy-current testing 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, eddy current testing of the tubes would indicate if the adjacent tubesheet was degrading. The corrective action program provides an acceptable means of review, evaluation, and corrective action. Because the tubesheet is over 22 inches thick and eddy current testing can reflect tubesheet loss, this visual inspection (augmented by eddy current testing) is adequate to maintain the pressure boundary function of the tubesheet.

   The applicant's RAI response does not include sufficient detail for the staff to determine whether the proposed inspection will provide reasonable assurance that this aging effect will be adequately managed during the period of extended operation. The applicant does not specify the acceptance criteria (for the visual and eddy current testing), nor the basis for the acceptance criteria. The applicant should specify these requirements.

Response:

There are no industry acceptance criteria for visual inspections of the tubesheet. Eddy-current testing of the tubes is performed per technical specifications and NEI 97-06 guidance documents. Based on the thickness of the tubesheet and that there is no site or industry experience related to tubesheet cracking, OPPD considers this inspection adequate management of the pressure boundary.

6. In response to RAI B.2.9-2, the applicant described the inspection program related to the primary-side tubesheet and primary head as follows: 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.

   The applicant's RAI response does not include sufficient detail for the staff to determine whether the proposed inspection will provide reasonable assurance that this aging effect will be adequately managed during the period of extended operation. 1) The applicant does not specify the extent (other than "portions") of the tubesheet and head that are visually inspected, or the basis for this extent. 2) The applicant did not describe the method or technique (including codes and standards) used for the visual inspection. 3) The applicant should specify the acceptance requirements, and the basis for these acceptance requirements, utilized to analyze the condition of the component based on the inspection results.

Response:

1) The entire primary side tubesheet and internal head are inspected.

2) The methods and technique were described (i.e., visual inspection by remote camera). There are no codes and standards which address this visual inspection.

3) There are no industry acceptance criteria regarding visual examinations of the primary head and primary side tubesheet. Since industry experience has not indicated cracking to the primary head and primary side tubesheet, and because tight primary water quality standards result in minimal corrosion levels compared to the thickness of these components, OPPD considers the visual inspection of these components as adequate management of cracking.

Overall:

Considering the staff found the inspection practices presented in OPPD's response to GL 97-06 provided reasonable assurance that the condition of the steam generator internals are in compliance with current licensing basis for FCS, and considering that these practices continue at FCS and are conservative with regard to results of the CEOG Evaluation of Degraded Secondary Internals Operability Assessment and site and industry operating experience, OPPD considers that their management of these "added-scope" components is adequate for the period of extended operation.

e. In LRA Section B.3.1, Omaha Public Power District (OPPD) states that the chemistry-related portions of Alloy 600 program are addressed in the FCS chemistry program, and that this is a deviation against the [Scope] and [Preventative Actions] program attributes for GALL AMP XI.M11, "Nickel-Alloy Nozzles and Penetrations." This implies that OPPD considers that implementation of the chemistry program, as related to controlling the ingress of ionic impurities and dissolved oxygen into the RCS coolant, can prevent or mitigate degradation in the FCS Alloy 600 components and their associated Alloy 182/82 weld materials. Staff review of the chemistry program (LRA Section B.1.2) finds no indication that the chemistry AMP, as implemented consistent with GALL program XI.M2, "Water Chemistry," contains the chemistry-related portions of the Alloy 600 Program. Since this has been identified as an exception to the [Scope] program attribute for XI.M11, OPPD needs to amend the description of the chemistry program, as provided in Section B.1.2 of Appendix B to the FCS LRA to state that the scope of the program includes the chemistry-related portions of the FCS Alloy 600 Program.

Response:

The first sentence of FCS LRA Appendix B, Section B.1.2, Chemistry Program has been revised to read, "The FCS Chemistry Program is consistent with XI.M2, Water Chemistry, and the chemistry related portions of XI.M11, Nickel-Alloy Nozzles and Penetrations, and XI.M21, Closed-Cycle Cooling Water System, as identified in NUREG-1801." OPPD is, therefore, consistent with the GALL Report relative to Alloy 600 Program chemistry requirements.

f. OPPD's Alloy 600 program for the FCS VHP nozzles and other RCS Class 1 components made from nickel-based alloys (including associated Alloy 182/82 filler metals) and the applicant's response to NRC Bulletin 2002-02 indicates that the aging management program (AMP) is mainly dependent on visual examinations that are implemented in accordance with the OPPD boric acid inspection program. In RAI B.3.1-1, the staff requested a commitment by OPPD to implement these recommended inspection methods, inspection frequencies, and acceptance criteria that result from industry initiatives by the CEOG or the MRP Integrated Task Group on Inconel materials (including Alloy 600 and Alloy 182/82 materials) and are recommended for managing stress corrosion cracking (including PWSCC) of Inconel components, as found acceptable by the NRC, as well as any additional requirements that may result from the staff's resolution of the industry's responses to NRC Bulletin 2002-02, and/or the V.C. Summer hot-leg nozzle cracking issue. The applicant's response to RAI B.3.1-1, dated December 19, 2002, did not provide the type of commitment requested by the staff. Instead, the response to RAI B.3.1-1 stated that the issue of PWSCC in the FCS Alloy 600 components was an issue that would be resolved during the current operating term for FCS.

Although the staff does concur that the issue of PWSCC in the VHP nozzles of domestic PWRs is a current licensing term issue that is outside of the scope of license renewal pursuant to 10 CFR 54.30, the staff is currently assessing the industry's responses to NRC Bulletin 2002-02 to determine whether the industry's inspection program for the VHP nozzles of domestic PWRs is sufficient to manage PWSCC in these nozzles prior to a loss of structural integrity, and specifically, for OPPD, prior to a loss of structural integrity in any of the VHP nozzles at FCS. The staff is currently not in agreement with the industry as to which type of inspection methods will be sufficient to manage PWSCC in the VHP nozzles of domestic PWRs. The staff, therefore, reiterates its request for a commitment from OPPD to implement those recommended inspection methods, inspection frequencies, and acceptance criteria that result from industry initiatives by the CEOG or the MRP Integrated Task Group on nickel-based alloys and are recommended for managing stress corrosion cracking (including PWSCC) in Class 1 nickel-based alloy components (including Class 1 components fabricated from Alloy 600 base metals and Alloy 182/82 filler materials), as found acceptable by the NRC, as well as any additional requirements that may result from the staff's resolution of the industry's responses to NRC Bulletin 2002-02 and/or the V.C. Summer hot-leg nozzle cracking issue.

Response:

In addition to stating that this is a CLB issue, OPPD's response to RAI B.3.1-1 also states that the FCS Alloy 600 Program currently includes a requirement to monitor industry operating experience and implement program enhancements as necessary. By making this a requirement of the Alloy 600 Program, OPPD has committed to incorporating industry activity recommendations or mandates as applicable. This will also be a commitment that is identified in the LR SER.

This means that OPPD plans to implement those recommended inspection methods, inspection frequencies, and acceptance criteria resulting from industry initiatives (by the CEOG or the MRP Integrated Task Group on nickel-based alloys) that are acceptable to the NRC for managing stress corrosion cracking (including PWSCC) in Class 1 nickel-based alloy components (including Class 1 components fabricated from Alloy 600 base metals and Alloy 182/82 filler materials). OPPD also plans to implement any additional requirements that may result from the staff's resolution of the industry's responses to NRC Bulletin 2002-02 and/or the V.C. Summer hot-leg nozzle cracking issue, as applicable.

POI-8

The staff requests that the applicant address the following issues in LRA Section 3.1:

a. The leakage detection lines, or closure head vent lines, have been included within the 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. Item A2.1.4 in Section IV of NUREG 1801 indicates vessel flange leak detection lines require further plant-specific evaluation. Since this line functions as a pressure boundary for the vessel flange, the applicant is requested to address the plant-specific review in item A2.1.4 in Section IV of NUREG-1801, and identify the materials used in the leakage detection line, the method of pressurizing the lines and the inspection methods that are used to detect crack initiation and growth due to stress corrosion cracking that initiates on the inside surface.

Response:

AMR Item 3.1.1.06 is equivalent to GALL Report Item IV.A2.1.4. AMR Item 3.1.1.06 specifies in Discussion Item 3 that the lines are fabricated of stainless steel. Discussion Item 2 specifies that the Chemistry, ISI, and One Time Inspection Programs are to be utilized to manage the aging of these lines. The One Time Inspection Program is to be utilized to verify that weld cracking is not occurring. Combinations of NDE, including visual, ultrasonic, and surface techniques, are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR 50, Appendix B. For small-bore piping less than NPS 4 inches, including pipe, fittings, and branch connections, a plant-specific destructive examination of replaced piping due to plant modifications or NDE that permits inspection of the inside surfaces of the piping is to be conducted to ensure that cracking has not occurred. Follow-up of unacceptable inspection findings includes expansion of the inspection sample size locations. OPPD is treating these lines in the same manner as other small bore RCS lines.

b. Loss of section thickness due to erosion could occur in steam generator feedwater impingement plates and supports. The GALL report recommends further evaluation of a plant-specific aging management program to ensure that this aging effect is adequately managed. Acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 of this standard review plan). The staff reviews the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects.

   The applicant indicates that this aging effect is not applicable to FCS. The applicant has not indicated why it is not applicable to FCS. If FCS has steam generator feedwater impingement plates and supports, or their equivalent, the applicant must provide the results of its AMR, identify aging management programs to manage loss of section thickness due to erosion and provide justification for the program. The applicant should clarify whether FCS has steam generator feedwater impingement plates and supports, or their equivalent. If so, provide the results of the AMR and identify aging management programs to manage loss of section thickness due to erosion.

Response:

LRA AMR Item 3.1.1.14 is clear in the Discussion column that these components are not applicable to FCS; i.e., they are not present in the FCS SG design.

c. 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 inspection program (RVII, LRA Section B.2.8) is credited with managing aging. In RAI 3.1.3-1, the staff requested the applicant to identify plant-specific experience with respect to cracking and loss of preload of thermal shield bolting.

   In response to RAI 3.1.3-1, the applicant committed to incorporate an augmented inspection of the thermal shield bolting or pins within the reactor vessel internals inspection program. The thermal shield 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. Based on the success of the thermal shield monitoring program in detecting loss of preload, and the commitment to incorporate this program in the reactor vessel internals inspection program, the staff agrees that a loose parts monitoring program is not necessary and the reactor vessel internals inspection program will be adequate for detecting aging effects for the thermal shield bolting or pins. The USAR supplement for the reactor vessel internals inspection program (A2.2.20) does not identify that the thermal shield monitoring program is included within the reactor vessel internals inspection program. The applicant should include this information within its USAR supplement.

Response:

LRA Appendix A, Section A.2.20, has been revised to read as follows:

"The Reactor Vessel (RV) Internals Inspection Program includes the following elements for cast austenitic stainless steel (CASS) and other reactor vessel internal components:

(a) determination of the susceptibility of CASS components to thermal aging and neutron irradiation embrittlement, (b) identification of the most susceptible or limiting items, (c) development of appropriate inspection techniques to permit detection and characterizing of the feature (cracks) of interest and demonstrate the effectiveness of the proposed technique, (d) implementation of required inspections prior to the period of extended operation, and (e) periodic monitoring of vessel internals vibration."

d. In response to RAI 3.1.2-1 the applicant indicates that 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 examination was 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. The applicant indicates that they will continue to visually inspect and perform a dye-penetrant exam on the two remaining RCP thermal barriers when the rotating assemblies are refurbished. Based on the operating and inspection results to date on the RCP thermal barriers, the staff agrees that periodic inservice inspection of the RCP thermal barriers is not necessary. The staff agrees that visual inspection and dye penetrant examination during refurbishment will be adequate to monitor crack initiation and growth in the RCP thermal barriers. This inspection program should be continued during the license renewal period. The staff requests that during the license renewal period the applicant commit to visual inspection and dye-penetrant examination of RCP thermal barriers that are accessible during refurbishment. If cracks are discovered during refurbishment, the applicant should implement a program for inspection of the RCP thermal barriers in the other RCPs.

GALL AMP XI.M32 indicates the one-time inspection is to be utilized when an aging effect is not expected to occur but there is insufficient data to completely rule it out or an aging effect is expected to progress very slowly. The one-time inspection provides additional assurance that aging is either not occurring or the evidence of aging is so insignificant that aging management is not warranted. In order to determine whether loss of material resulting from crevice corrosion in the presence of sufficient levels of oxygen, halogens, sulfates, or copper is not expected to occur, the applicant must review its inspection records to determine whether this aging effect has previously occurred at FCS for the components listed in Item 3.1.2.02. If it has not occurred, the proposed program is acceptable. If a component has experienced this aging effect in the past, the applicant should identify when it occurred, the corrective action, and the reason for not expecting it to occur in the future. If this aging effect is expected to occur in the future, periodic examination is necessary.

Response:

This is not planned to be a periodic activity. This refurbishment is being done once for each pump. As stated in the RAI response, this refurbishment of each pump will be credited in the One Time Inspection Program. The "A" and "C" pumps have already been refurbished and the "B" and "D" pumps will be completed over the next couple of outages. The thermal barriers of those pumps will also be inspected as part of the refurbishment.

If cracking of the RCP thermal barrier is detected during either of these remaining refurbishments, this will be documented on a Condition Report under the Corrective Action Program. An assessment will then be performed to determine what actions will be required to monitor the condition of the RCP thermal barriers in the future. (The preceding is not a new OPPD commitment, but is a description of how such a discovery would be addressed under OPPD's Corrective Action Program.)

Additionally, there has been no operating experience at FCS relative to crevice corrosion of nickel-based alloys. It is generally considered not to be a credible aging mechanism for these alloys. Per RAI response 3.1.2-5, 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.

e. Attachment 3 to the FCS engineering analysis (EA-FC-00-088) provides a program description and a direct comparison of the ten elements in GALL AMP XI.M32 and the FCS activity to implement the one-time inspection program. EA-FC-00-088 indicates that the one-time inspection program will include RC system small-bore piping that is susceptible to crack initiation and growth due to stress corrosion cracking or cyclic loading. Although the FCS engineering analysis document specifies the criteria in GALL AMP XI.M.32, cyclic loading is a general requirement. In order to designate locations that are most susceptible to failure from cyclic loading, the mechanism which could cause age-related degradation must be specified. The staff is concerned that cyclic loading that is caused by thermal fatigue resulting from thermal stratification or turbulent penetration could lead to the loss of function in small bore piping. Therefore, the applicant should clarify whether the one-time inspection program will include RC system small-bore piping that is susceptible to crack initiation and growth due to stress corrosion cracking or thermal fatigue resulting from thermal stratification or turbulent penetration

Attachment 6 to EA-FC-00-88 identifies all components that are to be included in the one-time inspection program. This document indicates that RC stainless steel small-bore piping components in borated treated water will receive augmented inspection using volumetric examination or equivalent. This document does not address carbon steel small-bore piping in the RC system. The applicant should confirm that there is no carbon steel small-bore piping with full penetration welds in the RC system. If there is carbon steel small-bore piping with full penetration welds in the RC system, the applicant should include this piping in its one-time inspection program or justify its exclusion.

Response:

Since FCS is a PWR having stainless steel loops, there is no carbon steel small bore piping in the reactor coolant system. It is a borated water system; therefore, the use of carbon steel would be inappropriate.

FCS stainless steel small bore piping meets the GALL Report AMR Item IV.C2.1.5 requirements for the AERM of crack initiation and growth due to the mechanisms of stress corrosion cracking and thermal and mechanical loading. Water Chemistry, the ISI Program, and the One-Time Inspection Program have been credited per that requirement; therefore, OPPD is consistent with the GALL Report relative to the aging management of RCS small bore piping. OPPD commits to the requirements in GALL Report Section XI.M32 relative to the inspection of small bore RCS piping and to base inspections on those locations where small bore piping is subject to thermal cycling stratification or turbulent penetration.

f. Programs identified in NUREG-1801 are generic programs. When components experience unusual aging effects, the programs identified in JUREG-1801 may not be applicable. CRD housings (LRA Table 3.1-1, roe 3.1.1.25) are identified as being susceptible to SCC and PWSCC with aging management provided by the inservice inspection (B.1.6) and chemistry (B.1.2) programs. 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 housings have similar designs.

Because this operating experience was not considered in the development of the LRA, the staff requested the applicant to consider whether the proposed inservice inspection and chemistry programs would be adequate for managing the aging effect of cracking of the CRD housings at FCS. In response to RAI 3.1.1-4, the applicant indicates that 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).

The applicant considers this to be a current licensing basis issue, with the resolution to be incorporated into the appropriate AMPs. The applicant indicates that it 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. The applicant's commitment to apply recommended or mandated activities resulting from the CEDM Material Reliability Management Plan ensures that CRD housings will receive adequate aging management during the license renewal term. The staff requests the applicant to include a description of the program to manage CRD housings in the USAR Supplement.

Response:

OPPD commits to applying recommended or mandated activities resulting from the CEDM Material Reliability Management Plan with regard to management of CRD housings. OPPD will submit the revised AMPs for staff approval prior to the period of extended operation to ensure that the revised AMPs are adequate to for managing aging effects of the CRD housings.

Section A.2.14 from Appendix A of the LRA has been revised to incorporate this response as follows:

"The Fort Calhoun Station Inservice Inspection Program implements the examination requirements of the ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, Subsections IWB, IWC, IWD, and IWF. The program consists of periodic volumetric, surface and/or visual examination of components and their supports for assessment, signs of degradation, and corrective actions. This program is in accordance with ASME Section XI, 1995 edition through the 1996 addenda.

Relative to the application of the ISI Program to the management of the CRD housings, the program will be revised, as necessary, to incorporate the results of the investigative activities that are being performed under OPPD's CEDM Material Reliability Management Plan. Applicable results/recommendations from industry initiatives relative to FCS CEDM aging management will also be evaluated for implementation at FCS. Any recommended or mandated changes to the ISI Program relative to the management of CEDM aging will be submitted to the NRC for review and approval prior to entry into the period of extended operation."

POI-9

The staff requests that the applicant address the following issues in LRA Section 3.2:

a. In LRA Table 3.2-1, row 3.2.1.08, the applicant stated that the ESF components in FCS are not serviced by an open-cycle cooling system. The AMR inspection was to confirm that there are no heat exchangers in the ESF systems that will be serviced by the open-cycle cooling water system program of NUREG-1801. Based on the information provided by the applicant, the AMR inspection found that there are several ESF heat exchangers for which raw water would be utilized should CCW not be available in an emergency situation. The staff considers that the worst-case scenario should be accounted for in the AMR for these heat exchangers. The applicant is, therefore, requested to identify the aging effects requiring management for these heat exchangers, which will be exposed to raw water environments during emergency situations, and the associated AMP.

Response:

The normal operating condition of the ESF heat exchangers is with Component Cooling Water (CCW) as the medium, not the Raw Water (RW) system. The RW system is only credited for operation should there be a failure of the CCW system. According to 10 CFR Part 54, Statements of Consideration, III.c(ii), "Consideration of ancillary functions would expand the scope of the license renewal review beyond the Commission's intent." OPPD considers the operation of the RW system upon the failure of the CCW to be an ancillary (auxiliary) function, and not an Intended Function. Therefore, the raw water environment is not considered for these heat exchangers for the period of extended operation.

b. In RAI 3.2.2-1, the staff requested the applicant to clarify the statement made in LRA Table 3.2-1, row 3.2.1.04, under "Discussion". Specifically, the applicant clarified in its letter of December 19, 2002, that it should read, " No FCS containment isolation valves and associated piping in systems that are addressed in this or other sections of this application were determined to be ....," in place of "No FCS containment isolation valves and associated piping in systems that are not addressed in this or other sections of ...." In a meeting held on November 21, 2003, the staff clarified that the applicant should provide the basis of its determination that the above components are not subject to the aging effect of loss of material due to MIC. This information was not provided in the applicant's letter of December 19, 2002. The applicant is, therefore, requested to discuss the relevant material/environment combinations for the subject components to ensure that the components will not be subject to the aging effect of loss of material due to MIC.

Response:

The RAI Item was actually 3.2.1-1 and the response was supplemented to state that the operating experience at FCS, per its condition reporting history, is such that MIC has never been observed in the applicable systems. MIC is not, therefore, deemed to be an applicable mechanism for the loss of material AERM for the systems identified in the RAI response.

Visual inspections that discover corrosion cannot identify the mechanism that is causing the corrosion. If MIC was to occur, it would be discovered by the credited activities that monitor the loss of material AERM. A Condition Report would be generated, as a function of the Corrective Action Program, to report the discovered corrosion. An evaluation of the corrosion would be performed to determine its cause. If the mechanism was determined to be MIC, appropriate corrective actions would be taken and activities implemented to mitigate and monitor the mechanism.

POI-10

The staff requests that the applicant address the following issues in LRA Section 3.3:

a. With regard to the chemical and volume control system, in RAI 3.3-1, the staff asked for clarification for several links in the LRA. In its response dated December 12, 2002, the applicant clarified that link 3.3.1.08 would be used instead of 3.4.1.10 for the letdown heat exchanger. During the AMR inspection, in response to the staff's questions about the aging management of this component, the applicant also clarified that the letdown heat exchanger would be managed using the cooling water corrosion program (link 3.3.1.08), and that the inspection would cover both the primary side and the cooling water side of the heat exchanger. The staff finds that this clarification is consistent with the GALL recommendations and is acceptable. However, the applicant should provide this clarification under oath and affirmation.

Response:

Aging management of the letdown heat exchanger will be managed using the Cooling Water Corrosion Program, and the inspection will cover both the primary side and the cooling water side of the heat exchanger.

b. The LRA indicated that the aging effects and aging management of the regenerative heat exchanger are consistent with GALL. However, during the onsite inspection of the applicant's aging management programs, the staff identified that this was not the case. In a conversation with the staff during the inspection, the applicant stated that the regenerative heat exchanger is made of stainless steel with an all-welded construction, such that the internals are inaccessible. The applicant also stated that the aging management of the regenerative heat exchanger would consist of the chemistry program, with further evaluation of cracking due to SCC provided by inspection of the welds via the inservice inspection program. The applicant considered this adequate aging management to support the pressure boundary intended function. The applicant stated that they would docket this information.

However, the staff notes that degradation of the regenerative heat exchanger internals could allow inventory to flow from the charging to the letdown side of the chemical and volume control system. This would reduce the effectiveness of the system for managing reactor coolant system chemistry, and may also reduce the ability of the system to inject borated water during an event; therefore, the proposed aging management may not be adequate to ensure that the intended function of the heat exchanger is maintained.

Describe inspections of the regenerative heat exchanger internals that would verify the absence of the identified aging effects, or justify that degradation of the internals would not result in loss of function.

Response:

See the response to POI-10.i.

c. In LRA Table 2.3.3.8-1, the applicant identified a link to LRA AMR item 3.3.1.07 for the accumulators. During the AMR inspection, the applicant clarified that link 3.3.1.07 should be 3.3.1.05. The applicant should revise LRA Table 2.3.3.8-1 and submit it for staff review.

Response:

Revised LRA Table 2.3.3.8-1, Instrument Air, is included in Appendix A of this letter.

d. The staff noted that LRA Table 2.3.3.17-1 deals primarily with external environments and did not appear to cover the internal environments that would be expected in the liquid waste disposal system. In RAI 3.3.1-12, the staff asked the applicant to describe the internal environment(s) of the system. By letter dated December 19, 2002, the applicant stated that the system internal environment was primarily borated treated water inside containment, and raw water (fire water) in the auxiliary building. The applicant stated that the link to LRA Table 3.3.2 item 96 covered the stainless steel piping in the borated water environment. The applicant added a link to LRA Table 3.3.1 item 16 to cover carbon steel and stainless steel pipes, fittings, and valve bodies in raw water. Since for many plants the liquid waste disposal system is connected to floor drains, the staff questions the applicant's assertion that the piping inside containment is only subjected to borated, treated water. The staff believes that the environment may contain higher concentrations of impurities than would be found in borated, treated water and, consequently, the applicant may not have adequately identified the aging effects for the piping inside containment. Discuss the frequency of inspections of the liquid waste disposal system piping inside containment. Justify the inspection frequency considering the expected internal environment, including the potential for high impurity concentrations due to system connections to floor drains or other potential sources of impurities, and subsequent evaporation/concentration of impurities.

Response:

LRA Table 2.3.3.17-1 has been modified (see Appendix A) to change the intended functions from "Pressure Boundary" and "Water Suppression Support" to "Fluid Boundary." The waste disposal drain piping that is in scope does not have a pressure retention function. It is not ever pressurized. It is in scope only for fire water removal in the event of a fire.

There are no other contaminants in containment that would cause additional AERMs above and beyond those that have already been included for this piping. Stainless steel piping with a water environment is subject only to cracking and this assumption is conservative for this application because for cracking to occur in stainless steel, specific halide levels are required with elevated temperatures and material stress. All of these elements are not present in the liquid waste disposal piping. Even if the halides were present, typically the temperature would not be elevated and the piping is not pressurized so there is no stress. Cracking could not, therefore, occur.

The link to AMR Item 3.3.1.16 was made in error and is not correct. For the Auxiliary Building waste disposal piping, portions of that system are only in scope for fire protection requirements to be able to drain fire water (raw water) from Auxiliary Building spaces in the event of a fire. The piping is there to form a channel for drainage through the floor to reach the sumps in the basement where it will be pumped out. The piping was no longer needed once the concrete was poured and the channel was formed. The drainage will take place whether the metal piping is there or not. Piping embedded in the floor is not accessible for inspection.

The key here is that the piping itself is not necessary for the drainage channel that is present in the floor once the concrete set around the embedded piping. The required flooding drainage function would still be completed without the piping. There would, in fact, be an even greater flow area to accommodate more water if the piping wasn't there.

e. Table 3.3-2 of the LRA states that the periodic surveillance and preventative maintenance program will provide aging management for the stainless steel components in the borated treated water environment. Section 2.3.3.17 of the LRA indicates that these components are within the scope of license renewal due to their function to provide containment isolation. The staff notes that, while borated treated water may be the expected environment during an event for which this system has a license renewal intended function, in many plants the liquid waste system is connected to floor drains and, as such, the piping inside containment is likely to contain water with higher impurities than borated, treated water. Therefore, citing this environment may not result in an adequate frequency of inspection or inspection for all applicable aging effects. Discuss the frequency of inspections of the liquid waste disposal system piping inside containment. Justify the inspection frequency considering the expected internal environment, including the potential for high impurity concentrations due to system connections to floor drains or other potential sources of impurities, and subsequent evaporation/concentration of impurities.

Response:

There are no other contaminants in containment that would cause additional AERMs above and beyond those that have already been included for this piping. Stainless steel piping with a water environment is subject only to cracking and this assumption is conservative for this application because for cracking to occur in stainless steel, specific halide levels are required with elevated temperatures and material stress. All of these elements are not present in the liquid waste disposal piping. Even if the halides were present, typically the temperature would not be elevated and the piping is not pressurized so there is no stress. Cracking could not, therefore, occur.

f. In RAI 3.3.1-13, the staff asked for clarification of the aging effects of carbon steel piping in concrete, since experience has shown that steels can degrade in a concrete environment. By letter dated December 19, 2002, the applicant stated that, if through-wall perforation of liquid waste disposal system piping occurred, there would still be a clear channel for drainage of fire suppression water from the area of concern down to the sump, and therefore no aging management is required. While this is generally in keeping with the intended function of the system, the applicant has not demonstrated that the aging would be limited to a through-wall perforation as opposed to blockage of the piping. Justify the assumption that aging of the piping in question cannot lead to blockage.

Response:

There is no aging effect of "blockage" in the GALL Report or in any LRA that has been submitted to date. The drain lines at FCS are pitched to drain, do not contain dead legs, are subject to trickle flow rather than full flow, and the water most likely to be drained does not contain any sediment (like raw water does). Additionally, since the piping is normally dry, any type of material buildup that could produce a blockage is unlikely. Furthermore, the piping diameter is such that should swelling occur due to corrosion, total blockage of the flow path would not occur.

g. Section 2.3.3.17 of the LRA indicates that the components in the auxiliary building are within the scope of license renewal due to their function of providing flood mitigation. These components are connected to floor drains. The staff notes that the LRA Table 3.3.1 item 16 link that was added in the response to RAI 3.3.1-12 for these components credits the cooling water corrosion program for aging management. For the raw water environment, the cooling water corrosion program is essentially a Generic Letter (GL) 89-13 program designed for cooling water systems. It is not clear to the staff how this program will be used to manage the aging of piping in the liquid waste disposal system. Explain how the cooling water corrosion program will be used to effectively manage the aging of piping in the liquid waste disposal system.

Response:

The link in LRA Table 2.3.3.17-1 for 'Pipes & Fittings' and 'Valve Bodies' to LRA AMR Item 3.3.1.16 is in error, and has been deleted. A revised LRA Table 2.3.3.17-1 has been included in Appendix A of this submittal. (See response to POI-10.d.)

h. It appears that the applicant has incorrectly determined that the GALL recommendations for the spent fuel pool cooling system (link 3.3.1-01) do not apply to FCS. For the piping, fittings, and other stainless steel components in the spent fuel pool cooling system exposed to borated, treated water, the applicant's December 12, 2002, response to RAI 3.3-1 clarified that the aging management is through link 3.3.3-01. This link addresses stress corrosion cracking of stainless steel in borated treated water, and uses the chemistry program with no backup inspections based on the GALL recommendations for ECCS systems with similar materials and environments. However, for the same materials and environments in the spent fuel pool cooling system, the GALL (link 3.3.1.01) recommends that the loss of material due to general, pitting, and crevice corrosion be addressed by the chemistry program coupled with inspections to verify that aging effects are not occurring, due to the potential for impurities to reach high concentrations in areas of low flow. Therefore, it is the staff's position that inspections should be performed to verify the effectiveness of the chemistry program for the stainless steel components in the spent fuel pool cooling system, as discussed in SRP-LR Section 3.3.2.2.1. Describe the inspections what will be performed of the spent fuel pool system components to verify that a loss of material is not occurring.

Response:

GALL Report Section VII.A3, Spent Fuel Pool Cooling and Cleanup for PWRs, states that the materials of construction are carbon steel. Loss of material for stainless steel is not an applicable AERM. The system at FCS is stainless steel so none of the items in GALL Report Section VII.A3 apply to FCS. General, pitting, and crevice corrosion are not applicable to stainless steel.

i. In a conversation with the staff during the AMR inspection, the applicant stated that the regenerative heat exchanger is stainless steel and is of an all-welded construction, such that the internals are inaccessible, and that aging management of the regenerative heat exchanger would consist of the chemistry program with further evaluation of cracking due to SCC provided by inspection of the welds via the inservice inspection program. The staff notes that degradation of the regenerative heat exchanger internals could result in bypassing of system flow. This would reduce the effectiveness of the system for managing reactor coolant system chemistry, and may also reduce the ability of the system to inject borated water during an event; therefore, the proposed aging management may not be adequate to ensure that the intended function of the heat exchanger is maintained. Describe inspections of the regenerative heat exchanger internals that would verify the absence of the identified aging effects, or justify that degradation of the internals would not result in loss of function.

Response:

A potential failure of the internal boundary between the two sides of the Regenerative HX would not affect the inventory available for injection during an accident. The only function of the boundary is to provide for heat transfer during normal letdown operation. That function is not required during an accident. The HX externals provide a pressure boundary function for retention of inventory and that function is conservatively maintained per LR AMR analysis (see the following USAR Section 9.2.3.1 quote).

The following explanation is presented to explain the reason for changing the classification of the regenerative heat exchanger from an ASME Section III, Class A, 1968 vessel (PSAR page IX-2-8) to an ASME Section III, Class C vessel in Table 9.2-3 above:

The Fort Calhoun Station regenerative heat exchanger was originally required to be an ASME Section III, Class A vessel following a similar classification assigned to the Palisades regenerative heat exchanger. A Class A vessel was chosen because the vessel was carrying high temperature-high-pressure radioactive reactor coolant water. It was a part of the only path for injecting boric acid into the reactor coolant system, and this classification was suggested by then existing Code practice. Evaluation of design codes and system safety classification criteria placed emphasis on safety function and radioactivity release to the environment rather than fluid properties. Therefore, as detailed design progressed, the minimum design requirements for the regenerative heat exchanger were reduced from Class A to Class C. This reclassification of the regenerative heat exchanger conforms to the General Design Criteria requirement that safety related components be designed to quality standards that reflect the importance of their safety function. The unit is located inside the containment building and failure of either the shell or tube side will not result in uncontrolled radioactivity release to the environment, nor prevent safe shutdown of the reactor.

POI-11

The staff requests that the applicant address the following issues in LRA Section 3.4:

LRA Table 3.4-2 states that copper alloy components operating in a deoxygenated environment are subject to loss of material due to crevice and pitting corrosion resulting from stagnant or low flow conditions, or due to wear from flow-induced vibration. The applicant credits the one-time inspection to manage this effect. This program is described in LRA Section B.3.5. The staff issued RAI 3.4.1-10 requesting the applicant to provide justification that the AMP at FCS will provide equivalent aging management for copper alloy components in the heat exchangers of the AFW system at FCS. In its response by letter dated December 19, 2002, the applicant stated that the activities of three separate programs, namely one-time inspection (B.3.5), selective leaching (B.3.6) and periodic surveillance and preventive maintenance (B.2.7), are deemed to be appropriate for providing aging management that is equivalent to the GALL report for cooling water programs.

On the basis of its review of the applicant's response, the staff concludes that a one-time inspection identified for copper alloy components in a deoxygenated treated water environment (LRA Table 3.4-2, Row numbers 3.2.0.3, 3.2.0.4) is not an adequate means of managing loss of material in that environment. The applicant should develop an AMP which will adequately manage this aging effect in the subject components during the period of extended operation. Similarly, for loss of material due to selective leaching of copper alloy in a deoxygenated treated water environment, the selective leaching program by itself is not considered an adequate means of managing loss of material in that environment. The applicant should develop an AMP which will manage this aging effect in the subject components during the period of extended operation. It is the staff's understanding that the applicant has proposed additional programs for the subject components in this environment during the AMR inspection. The applicant needs to make a commitment to this effect on the docket and modify Table 3.4-2 of the LRA accordingly.

Response:

For the components in deoxygenated treated water, One Time Inspection Program and Selective Leaching Program are credited in the referenced table. The Chemistry Program is also credited but was inadvertently omitted from the table. The Chemistry Program (B.1.2) has been added to LRA Table 3.4-2, row 3.4.2.03. The PS&PM program is credited for the lube oil side of the cooler, not the deoxygenated treated water side.

POI-12

The staff requests that the applicant address the following issues in LRA Section 3.6:

In LRA Table 2.5.2-1, the applicant identifies containment electrical penetrations as components that are within the scope of license renewal and subject to an AMR. In this table, the applicant identifies several links, including 3.6.1.01 and 3.6.1.02. The staff believes that the electrical penetrations may include low-level pigtails, which require aging management identified in LRA Table 3.6-1, link 3.6.1.03. The applicant should clarify whether low-level pigtails are included in the containment electrical penetrations and whether they will be managed by the non-EQ cable AMP.

Response:

LRA Table 2.5.2-1 has been revised (see Appendix A of this letter) to include the Component Type "Instrumentation Cable Pigtails" that have an intended function of "Electrical Continuity" and are linked to LRA AMR Item 3.6.1.03. These components will, therefore, be managed for aging by the Non-EQ Cable Aging Management Program.

Additionally, OPPD has revised LRA Appendix A, USAR Supplement Section A.2.5 and Appendix B, Aging Management Activities, B.3.4 as described below.

A.2.15 NON-EQ CABLE AGING MANAGEMENT PROGRAM

The FCS Non-EQ Cable Aging Management Program is a new program that will perform periodic visual inspections of non-EQ medium-voltage cables and instrument calibrations to asses cable conditions. Cable inspections will be performed prior to the period of extended operation and at an interval of not more than ten (10) years after the start of extended operation, This program considers the technical information and guidance provided in NUREG/CR-5643, "*Insights Gained From Aging Research,*" IEEE Std. P1205, *"IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations,"* SAND96-0344, *"Aging Management Guidelines for Commercial Nuclear power Plants-Electrical Cable and*

Terminations," and EPRI TR-109619, *"Guidelines for the Management of Adverse Localized Equipment Environments."*

B.3.4 NON-EQ CABLE AGING MANAGEMENT PROGRAM

The FCS Non-EQ Cable Aging Management Program will be consistent with XI.E1, *"Electrical Cables And Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,"* XI.E2, *"Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits,"* and XI.E3, *"Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,"* as identified in NUREG-1801.

Operating Experience:

There have been no age related failures of cable at FCS. Corrective actions have been implemented in response to cable degradation identified by IEN issued on the subject. There is extensive industry and FCS experience in establishing and monitoring the cables and other equipment. The program will be improved, as appropriate, as additional industry experience becomes available.

Conclusion:

The FCS Non-EQ Cable Aging Management Program provides reasonable assurance that aging effects will be managed, consistent with the NUREG-1801, Sections XI.E1, E2, and E3, such that non-EQ cables subject to aging management review will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

POI-13

The staff requests that the applicant address the following issues in LRA Section 4:

a. Item (e) in RAI 4.2-2 requested the applicant to identify the projected Charpy USE for each beltline material. In response to this item, the applicant provided a table, which indicates that the lowest predicted USE is 50.1 ft-lb. The table contains a column identified as "Position 2.2 Capsule Modified % USE Decrease." The applicant has not identified how the values in this column were determined. In addition, the initial USE for Weld Heat No. 12008/27204 is identified as 97.8 ft-lb. The actual initial Charpy USE data for this weld must be submitted to the staff for review. The staff requests that the applicant explain how the values in the column "Position 2.2 Capsule Modified % USE Decrease," were determined and provide the source and actual initial Charpy USE data for Weld Heat No. 12008/27204.

   Item (f) in RAI 4.2-2 requested the applicant to evaluate the impact of surveillance data on the projected Charpy USE. In response to RAI B.1.7-1, the applicant indicates that the FCS will be utilizing weld surveillance data from Mihama, Diablo Canyon Unit 1, Palisades supplemental capsules from FCS drop-out, and Salem Unit 2. In response to item f in RAI 4.2-2, the applicant provided a table which contains surveillance data from the FCS surveillance welds and plates and the Mihama (surveillance weld) plant; but does not contain data from Diablo Canyon Unit 1, Palisades supplemental capsules from FCS drop-out, and Salem Unit 2. In addition, the applicant has not explained the impact of the surveillance data on the projected Charpy USE for each beltline material. The staff requests that the applicant provide Charpy USE surveillance data from Diablo Canyon Unit 1, Palisades supplemental capsules from FCS drop-out, and Salem Unit 2, and explain the impact of all the surveillance data on the projected Charpy USE for each beltline material.

Until this data is provided, the staff cannot confirm that the projected Charpy USE at the expiration of the extended license for all beltline materials will exceed 50 ft-lb in accordance with the requirements in Appendix G, 10 CFR Part 50.

Response:

OPPD inadvertently provided an incorrect response to RAI 4.2-2 which used methodology similar to Position 2.2 from Regulatory Guide 1.99. That response is superseded by the revised response (below) which uses the Position 1.2 methodology from Regulatory Guide 1.99.

New Table A.3.1.4-1 has been incorporated into USAR Section A.3.1.4, Reactor Vessel Upper Shelf Energy. This table contains the response to RAI 4.2-2 items a through e.

Table A.3.1.4-1, Fort Calhoun Station Upper Shelf Energy Data for Operation to 48 EFPY

Plate/Weld Number[1]	Plate/Weld Heat No.[1]	Fluence at 1/4 t (n/cm^2)[2,3]	Cu (%)[1]	Initial USE (ft-lb.)	Position 1.2 % USE Decrease	Predicted Irradiated USE from Position 1.2 (ft-lb.)	Flux Type
D 4802-1	C 2585-3	2.28×10^{19}	0.120	75[1]	25	56.3	N/A
D 4802-2	A 1768-1	2.28×10^{19}	0.100	121[1]	23	93.2	N/A
D 4802-3	A 1768-2	2.28×10^{19}	0.110	77[1]	24	58.5	N/A
D 4812-1	C 3213-2	2.28×10^{19}	0.120	86[1]	25	64.5	N/A
D 4812-2	C 3143-2	2.28×10^{19}	0.100	87[1]	23	67.0	N/A
D 4812-3	C 3143-3	2.28×10^{19}	0.100	90[1]	23	69.3	N/A
2-410	51989	1.62×10^{19}	0.170	84[4]	35	54.6	Linde 124[5]
3-410	13253	1.62×10^{19}	0.221	110[1]	40	66.0	Linde 1092[5]
3-410	27204	1.62×10^{19}	0.203	94[1]	38	58.3	Linde 1092[5]
3-410	13253/12008	1.62×10^{19}	0.210	97[4] *	39	59.2	Linde 1092[5]
3-410	12008/27204	1.62×10^{19}	0.219	97[4]	40	58.2	Linde 1092[5]
9-410	20291	2.28×10^{19}	0.216	105[1]	43	59.9	Linde 1092[5]

[1] Reference: NRC RVID Version 2.0.1

[2] Reference: WCAP-15443, Revision 0, "Fast Neutron Fluence Evaluations for the Fort Calhoun Unit 1 Reactor Pressure Vessel," Table 6.2-1, "Calculated Neutron Exposure Projections at Key Locations on the Pressure Vessel Clad/Base Metal Interface."

[3] Reference: USNRC, Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," May 1988.

[4] Reference: Generic value that was approved in Letter from NRC (G. C. Lainas) to Chairman, CEOG (D. F. Pilmer), dated September 25, 1996, "Safety Evaluation of Report CEN-622, "Generic Upper Shelf Values for Linde 0091, 124, and 1092 Reactor Vessel Welds", June 1995; "Supplemental Information to C-E Owners Group Report CEN-622", June 1996."

[5] 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.

*Note: This value is missing from NRC RVID Version 2.0.1.

f)

Upper Shelf Energy Requirements

1. 10CFR50, Appendix G- Charpy upper-shelf energy for the reactor vessel beltline plates and welds of no less than 50 ft-lb throughout the life of the plant. (Can also use so-called equivalent margins analysis subject to NRR approval.)

2. Regulatory Guide 1.99, Revision 02- basis for prediction of upper shelf energy decrease for plates and welds given in Regulatory Position 1.2 and 2.2. "When credible surveillance data from the reactor in question are not available, calculation of ... should be based on the procedures in Regulatory Positions 1.1 and 1.2..." "When two or more credible surveillance data sets ...become available from the reactor in question, they may be used to determine the adjusted reference temperature and the Charpy upper-shelf energy of the beltline materials as described in Regulatory Positions 2.1 and 2.2, respectively." It is assumed for purposes of this evaluation that "credible surveillance data from the reactor in question" refers to meeting the five credibility criteria in Regulatory Guide 1.99, Revision 02 to the extent applicable to Charpy upper-shelf energy (as contrasted with transition temperature shift).

3. Regulatory Guide 1.99, Revision 02, Position 1.2- Use Figure 2 to estimate the decrease of Charpy upper-shelf energy as a function of copper content and neutron fluence as given in Table 4.2-2-1 (above) for each of the beltline plates and welds.

4. Regulatory Guide 1.99, Revision 02, Position 2.2- The only credible surveillance data from the Fort Calhoun reactor are the data set for the plate materials. These data consist of longitudinally oriented plate specimen data from each of the three capsules tested, and transversely oriented plate specimen data from two capsules tested. The requirement is for the transversely oriented plate material to have at least 50 ft-lb throughout the life of the plant. The measured value is 88 ft-lb after exposure to a neutron fluence of 1.28×10^{19} n/cm^2, a 27% decrease. Projection of these credible surveillance data to the 48 EFPY fluence for the plate, 2.28×10^{19}, in accordance with Position 2.2 results in a predicted 31% decrease. The upper shelf of the surveillance plate material in the transverse orientation after 48 EFPY is predicted to be 83.5 ft-lbs following position 2.2. As noted in Table 4.2-2-1 (above), the predicted Charpy upper-shelf energy for the other beltline plates is lower than that for the surveillance plate but in excess of the 50 ft-lb screening criterion from 10CFR50, Appendix G. [Note: The initial Charpy upper-shelf energy for five of the six beltline plates was conservatively estimated from Charpy specimens that were longitudinally oriented.]

5. Regulatory Guide 1.99, Revision 02, Position 2.2- There are no credible surveillance data from the Fort Calhoun reactor for the beltline weld materials. Therefore, the projections for the beltline welds were done following position 1.2 of Regulatory Guide 1.99, Revision 02. There are, however, surveillance data from other plants that are related to the Fort Calhoun reactor beltline weld materials with respect to the weld wire heats used. These data are summarized below in Table 4.2-2-2. [Note: No upper shelf data have been obtained for the irradiated Palisades supplemental surveillance capsule. It is expected that such information will be included in the test

report once it has been issued.] The highest neutron fluence exposure is 2.1×10^{19} n/cm^2 with the irradiated upper shelf energy reduced to 61 ft-lbs. This is also the lowest irradiated upper shelf energy value in Table 4.2-2-2. This data is from the third Mihama Unit 1 surveillance capsule. The projected values of Charpy upper-shelf energy for the beltline welds provided in Table 4.2-2-1 ranging from 55 to 66 ft-lbs are, therefore, consistent with the values of Charpy upper-shelf energy measured for the irradiated surveillance materials listed in Table 4.2-2-2.

Table 4.2-2-2, Irradiated Surveillance Weld Data from Other Plants

Plant Name and Capsule	Weld Wire Heat(s)	Fluence (n/cm^2)	Initial USE (ft-lbs)	Irradiated USE (ft-lbs)	Percent Decrease
DC Cook (CK) 1 Cap. T	13253	2.69E18	111	82	26
CK 1 Cap. X		8.13E18	111	73	34
CK 1 Cap. U		1.77E19	111	82	26
CK 1 Cap. Y		1.23E19	111	70	37
Diablo Canyon (DC) 1 Cap S	27204	2.84E18	98	87	11
DC 1 Cap Y		9.41E18	98	66	33
Salem (SA) 2 Cap T	13253	2.75E18	111	79	29
SA 2 Cap U		5.50E18	111	74	33
SA 2 Cap X		1.07E19	111	86	23
Mihama (MI) 1 Cap 1	12008/27204	6E18	98	68	31
MI1 Cap 2		1.2E19	98	61	38
MI1 Cap 3		2.1E19	98	61	38

Table 4.2-2-2 References:

1. Fluence as given in 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, and following references.

2. NRC RVID Version 2.0.1, and NUREG/CR-6551 database.

3. WCAP-13750, "Analysis of Capsule Y from the PG&E Diablo Canyon Unit 1 Reactor Vessel Radiation Surveillance Program, June 1993.

b. The USAR supplement does not contain the Charpy USE analysis that was performed in response to RAI 4.2-2. Since this analysis applies to the end of the period of extended operation, the applicant should revise the USAR supplement to include the results of the Charpy USE performed in response to RAI 4.2-2.

Response:

USAR supplement section A.3.1.4, "Reactor Vessel Upper Shelf Energy," second paragraph, has been revised in part to read,

> *Revised calculations have shown that the vessel beltline Charpy upper-shelf energy for the limiting weld will be approximately 54.6 ft-lbs, based on position 1.2 of RG 1.99. This value remains above the regulatory approved minimum of 50 ft-lbs through the period of extended operation. The existing Appendix G analysis has been revised to reflect that it bounds the minimum approved fluence value at the end of plant life. Therefore, the analysis is projected to the end of the period of extended operation, and is included below in Table A.3.1.4-1.*

This new table is the same as that shown in response to POI-13(a) above.

c. The applicant's December 19, 2002, response to RAI 4.3.1-1, item 1, provided a table which lists the current cycle counts for the design transients. The applicant indicated that these cycles were recorded in accordance with plant procedure standing order (SO)-O-23 on a monthly basis. The applicant indicated that the pressure differential transients due to reactor coolant pump stops and starts are not counted because the number specified (4000) is conservative. The applicant also identified several transients that are not counted under the procedure. These cycles involve power changes, operating pressure and temperature variations, and feedwater additions with the plant in hot standby conditions. The applicant indicated that these cycles will be estimated from a review of plant operating records to determine whether they should be counted by the fatigue monitoring program (FMP).

In response to Item 3, the applicant indicated that all design basis transients will be included in the FMP. The applicant indicated that a program basis document (PBD) would be generated to capture both the current and increased scope of the FMP, which includes incorporation of automated cycle counting and the analysis for environmentally-assisted fatigue. The applicant committed to complete the PBD and implement the enhanced FMP prior to the period of extended operation.

The applicant response did not provide cycle count for chemical and volume control system (CVCS) transients identified in LRA Section 4.3. In addition, Note 1 to the response to Item 1 implies that some transients may not be monitored by the FMP, whereas the response to Item 3 indicates that all transients will be monitored either directly or indirectly by the FMP. The applicant needs to provide additional clarification regarding how these transients are monitored by the FMP.

Response:

The CVCS system transient cycles are counted under Standing order SO-0-23, "System and Equipment Usage." The procedure logs the following transients:

- Loss of Charging (Limit: 500 cycles, Current Cycle Count estimated to be <50 cycles)*
- Intermittent Manual Charging Make-up Cycles (Limit: 200 cycles, Current Cycle Count estimated to be <50 cycles)*
- Loss of Letdown Cycles (Limit: 700 Cycles, Current Cycle Count = 163)
- Regenerative Heat Exchanger Long Term Isolation Cycles (Limit: 200 Cycles, Current Cycle Count = 4)
- Regenerative Heat Exchanger Short Term Isolation Cycles (Limit: 700 Cycles, Current Cycle Count = 25)
- Maximum Purification/Emergency Boration Cycles (Limit: 1000 cycles, Current Cycle Count estimated to be <100 cycles)*

  * These cycle counts are gross estimates due to incomplete logs. The estimates are based on the engineering judgment of the former system engineer and the design engineer that performed CVCS transient analyses in 1999. A Condition Report (CR) is being generated to address this issue within the Corrective Action Program so that a more accurate transient count/determination can be performed for the indicated transients prior to entry into the period of extended operation.

Two system transients listed in section 4.3 that are not addressed in SO-0-23 are Low Volume Control Tank Level and Boron Dilution. These were excluded from the transient counting based on engineering judgment that the operating conditions associated with these transients are well below the design conditions such that the fatigue usage associated with them compared to the other transients is insignificant. The CUF contribution associated with the 8080 cycles allowed for these two transients is, therefore, available to be utilized elsewhere if needed.

To expand on the last sentence of the previous paragraph, the cycle limits listed above for each CVCS transient are not design limits but rather engineering estimates for the number of cycles that might be incurred over the life of the plant. The significance of these numbers is that the CUF contribution for all CVCS transients is limited to a value no greater than 1.0, which is the limit imposed by the applicable design codes. An assumed number of cycles for each transient, based on the transient design operating conditions, is necessary to calculate a fatigue usage contribution for that transient. An increase in any one of the cycle number estimates approaching an assumed limit may necessitate a decrease in one or more of the others to satisfy the CUF limit of 1.0. Likewise, for transients like the Regenerative Heat Exchanger Short Term Isolation, where so few (25) of the allowable 700 cycles have been used, and the two transients addressed in the previous paragraph, the balance of their CUF contribution could be utilized elsewhere if the need were to arise as the plant approaches the end of the period of extended operation.

Further, the transients associated with the Regenerative Heat Exchanger (Short Term Isolation, Long Term Isolation, and Loss of Letdown) are the most limiting of the transients since it has been determined that the Regenerative Heat Exchanger is the most limiting component, with regard to thermally induced fatigue, in CVCS. Analysis has shown that the operating conditions for the transients associated with letdown are close to design operating conditions whereas the actual operating conditions for most other system transients are significantly less severe than the design operating conditions that have been assumed for them. Since FATIGUEPRO records actual system operating conditions at the time of a transient, its use to count some of the CVCS transients will provide OPPD with a history of the actual operating conditions associated with those transients such that a more accurate CUF can be determined and maintained for the balance of the life of the plant. Before the use of FATIGUEPRO, transient design conditions were assumed for transient CUF contribution determinations.

Additionally, since FCS is a base-load plant and several of the cycle limit assumptions were based on a load-follow operation mode, the number of actual cycles for those transients is expected to be well below the assumed limits at the end of the period of extended operation.

It is concluded that with the conservatisms that exist within the maintenance/monitoring activities for CVCS CUF, the system CUF will be below the 1.0 design limit at the end of the period of extended operation. Once the transients, for which gross estimates have been provided, have been more accurately accounted for, the CR corrective actions and the use of FATIGUEPRO will result in a more accurate monitoring of CVCS CUF.

d. The applicant's December 12, 2002, response to RAI 4.3.2-2 indicated that the environmental fatigue evaluations are complete and the analysis shows that the surge line is the only location where the cumulative usage factor (CUF) may exceed 1.0 during the period of extended operation. The applicant further indicated that the environmental fatigue of the surge line will be included in the FMP. The applicant should revise the USAR supplement to describe the completed environmental fatigue evaluation.

   The applicant's December 19, 2002, response to RAI 4.3.2-3 also indicated that the limiting surge line welds would be inspected prior to the period of extended operation. The applicant further indicated the results of these inspections will be utilized to assess the appropriate approach for addressing environmentally-assisted fatigue of the surge lines. The applicant indicated that the approach developed could include one or more of the following:

   1. Further refinement of the fatigue analysis to lower the CUF(s) to below 1.0, or

   2. Repair of the affected locations, or

3. Replacement of the affected locations, or

4. 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).

The applicant indicated that, if Option 4 is selected, the inspection details, including scope, qualification, method, and frequency will be provided to the NRC for review prior to the period of extended operation. The applicant should include this information in the USAR supplement.

Response:

For commitments listed in the Safety Evaluation Report, OPPD will include this list of commitments in an appropriate subsection of the FCS USAR Supplement for License Renewal.

e. The applicant's December 19, 2002, response to RAI 4.3.2–1 provided the calculated environmental usage factors for the six component locations listed in NUREG/CR-6260. The calculated usage factors are less than 1.0 for all components except for the surge line elbow. The applicant's response indicates that the usage factors for two components, the surge line elbow and the charging line nozzle, were based on anticipated cycles for a 60-year plant life consistent with Table 5-32 of NUREG/CR-6260. The statement in the applicant's response is not clear to the staff. The applicant should clarify whether the evaluations are based on the number of anticipated cycles for 60 years of operation at FCS. The applicant should also clarify whether the number of cycles assumed in these evaluations is included in the FMP to provide assurance that the evaluations remain valid during the period of extended operation.

Response:

For the two asterisked values (the surge line elbow and the charging line nozzle) in the referenced RAI response (RAI 4.3.2-1), the CUF evaluation is based on the <u>estimated</u> number of FCS cycles that these SSCs will see during 60 years of operation, not the design number of cycles.

The number of cycles assumed for the evaluation of the charging line nozzle will be included in the Fatigue Monitoring Program Basis Document, when it is generated, to assure that a CUF of 1.0 is not exceeded.

As reiterated in POI-13.d, prior to entry into the period of extended operation, the surge line elbow is going to undergo further evaluation to address the environmentally-assisted fatigue issue associated with that component.

f. The staff review of the concrete containment tendon pre-stress TLAA indicated that the applicant is missing an important acceptance criterion in the description of the TLAA. In RAI 4.5-1, the staff requested information regarding this acceptance criterion as follows:

> 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).

In response, the applicant stated that the acceptance criterion in the LRA complies 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. A discussion of this evaluation should be added to the USAR supplement.

Response:

See response to POI 13.g.

g. The applicant does not provide an adequate quantitative evaluation based on the prior tendon inspections. In RAI 4.5-2, the staff requested the following information:

> 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 Containment."

In response, the applicant argues that because it is using 10 CFR 54.21(c)(1)(iii), i.e. managing the TLAA through aging management, it need not provide such information. The staff recognizes the applicant's choice. However, the staff needs the quantitative data of trend lines, as part of the operating experience, for making a reasonable assurance conclusion regarding this TLAA for the period of extended operation.

Response:

OPPD is including the data from Section VIII of the last tendon inspection report as Appendix C of this submittal. The data in the report provides inspection results for all but the 2nd inspection.

Using the data from the report for the Helical Regression Forecast (p.42 in the report), at the current tendon force decay rate for the 95% confidence data, at 60 years the helical tendon force will be 601 kips and the design minimum force is 584 kips. At that same helical tendon force decay rate, there is, therefore, at the end of the period of extended operation, a margin of 25 to 30 years before the design minimum helical tendon force is reached.

Using the data from the report for the Dome Regression Forecast (p. 43 in the report), at the current tendon force decay rate for the 95% confidence data, at 60 years the helical tendon force will be 603 kips and the design minimum force is 589 kips. At that same dome tendon force decay rate, there is, therefore, at the end of the period of extended operation, a margin of 35 years before the design minimum helical tendon force is reached.

h. In its December 12, 2002, response to RAI 4.6-1, the applicant indicated that the recent analysis of the as-found buckling of the liner plate was performed using non-linear, 3D finite element analysis with loads applied in a fashion similar to the original analysis. The applicant indicated that an undeformed panel was analyzed to benchmark the new model against results from a comparable model from the original analysis. The applicant indicated that the new analysis resulted in a CUF of 0.141 for the 500 cycles of internal temperature variation due to heatup and cooldown. The applicant further indicated that 500 cycles is greater than the number of cycles expected for 60 years of plant operation. The applicant should verify that the thermal cycling due to outdoor temperature variation and LOCA does not result in insignificant fatigue usage. The applicant indicated that no penetration sleeves were contained in the new analysis. The applicant should also clarify whether the current evaluation bounds the fatigue usage in the penetration area.

Response:

The fatigue analysis for the liner plate as found buckling included cyclic conditions for outdoor air annual temperature changes and LOCA transients, however the contribution to fatigue usage factor for the outdoor air temperature variations was insignificant. The location of the Containment liner plate where the buckling had occurred is remote from any containment penetrations and had no effect on the stresses or fatigue analysis at the penetration.

i. The applicant provided a summary description of the containment liner plate and penetration sleeve fatigue TLAA in Section A.3.5 of the USAR supplement. The applicant indicates that an evaluation of the liner plate as-found buckling for a 60-year life will be completed prior to the period of extended operation. The applicant should update the USAR supplement to describe the results of the current evaluation as discussed in response to RAI 4.6-1.

Response:

LRA Section A.3.5, Containment Liner Plate and Penetration Sleeve Fatigue, has been revised as follows:

A.3.5 CONTAINMENT LINER PLATE AND PENETRATION SLEEVE FATIGUE

The containment liner and penetration sleeves were designed to be leak-tight under all postulated loading combinations by limiting strains to those values that have been shown to result in leak-tight pressure vessels. The results of the containment fatigue analysis indicated that when the maximum compressive strain in the liner was reached under operating conditions and subsequent cyclic temperature variations were applied to the liner, there was no significant change in stress and strain in concrete or steel for the second cyclic load indicating that shakedown had occurred during the first cycle of loading. Also, the investigation for 500 cycles of loading for the liner steel, anchor steel and anchor welds resulted in a computed cumulative usage factor of 0.05 as compared with an allowable usage factor of 1.0. Consideration of 60 years of operation as opposed to 40 would have no relevant impact on these results. However, the observed buckling of the liner is slightly larger than was assumed in the original analyses. This condition has been evaluated and found adequate for the current term. FCS has completed an analysis considering the actual bulges for a 60-year life. The re-analysis of the as-found buckling in the liner plate was performed using state-of-the-art, non-linear, 3D Finite Element Analysis methods with loads applied in a fashion similar to the original analysis. Both the original analysis and the re-analysis predict that panel stresses will exceed the material yield strength for the assumed loads. The purpose of the recent analysis was to determine the effect on fatigue usage caused by the existing buckling and the greater strains that will be incurred as compared to the original analysis. The cumulative fatigue usage factor derived in the original analysis was CUF=0.05 for 500 cycles of loading. The new analysis derived a CUF=0.141 for 500 cycles. The allowable usage factor is 1.0. It is not anticipated that even 500 cycles of the assumed loads will be incurred within the 60 year extended period of operation. Therefore, the containment liner plate and penetrations are acceptable through the period of extended operation.

j. The applicant should provide an updated USAR Supplement to Section A.3.6.2 of the application to reflect the statement in the applicant's response to RAI 4.7.2-1 regarding their commitment relative to the future resolution of the Inconel 82/182 PWSCC issue.

Response:

For commitments listed in the Safety Evaluation Report, OPPD will include this list of commitments in an appropriate subsection of the FCS USAR Supplement for License Renewal.

Commitment Summary

POI-1.c	Fuse holders within enclosures that are not considered active and subject to mechanical stress, fatigue and electrical transients will be included in the Fatigue-Monitoring Program (B.2.4).
POI-3.a	OPPD will perform a One Time Inspection of the circulating water discharge tunnel per the One Time Inspection Program (B.3.5). The circulating water discharge tunnel will be included in scope for license renewal as part of the Intake Structure.
POI-3.b	The portion of CCW that provides cooling to the SI Leakage Coolers is included within scope of License Renewal. The piping and components will be added to the License Renewal database and the CCW AMR evaluation will be revised to include these components prior to issuance of the SER.
POI-7.c	OPPD commits to performance of a one-time inspection prior to the period of extended operation to determine the condition of the fire protection fuel oil tank and verify it is not in a degraded condition.
POI-7.f	OPPD's response to RAI B.3.1-1 also states that the FCS Alloy 600 Program currently includes a requirement to monitor industry operating experience and implement program enhancements as necessary. By making this a requirement of the Alloy 600 Program, OPPD has committed to incorporating industry activity recommendations or mandates as applicable. This will also be a commitment that is identified in the LR SER.
POI-8.d	Per RAI response 3.1.2-5, 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.

POI-8.f	OPPD commits to applying recommended or mandated activities resulting from the CEDM Material Reliability Management Plan with regard to management of CRD housings. OPPD will submit the revised AMPs for staff approval prior to the period of extended operation to ensure that the revised AMPs are adequate to for managing aging effects of the CRD housings.
POI-13.c	These cycle counts are gross estimates due to incomplete logs. ...A Condition Report (CR) is being generated to address this issue within the Corrective Action Program so that a more accurate transient count/determination can be performed for the indicated transients prior to entry into the period of extended operation.
POI-13.d	For commitments listed in the Safety Evaluation Report, OPPD will include this list of commitments in an appropriate subsection of the FCS USAR Supplement for License Renewal.
POI-13.j	For commitments listed in the Safety Evaluation Report, OPPD will include this list of commitments in an appropriate subsection of the FCS USAR Supplement for License Renewal.

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Appendix A

TABLE 2.2-1 Plant Level Scoping Results	
SSC	**Within Scope of License Renewal?**
120 VAC (2.5.10)	yes
120/208 Miscellaneous Power Lighting	no
125 VDC (2.5.9)	yes
161 KV Substation Equipment (2.5.21)	**~~no~~ yes**[1]
22 KV	no
277/480 Miscellaneous Power Lighting *	no
345 KV Substation Equipment (2.5.21)	**~~no~~ yes**[1]
4.16 KV (2.5.6)	yes
480 Bus (2.5.7)	yes
480 Motor Control Centers (2.5.8)	yes
Acetylene Gas *	no
Administration Building *	no
Argon Gas *	no
Auxiliary Boiler *	no
Auxiliary Boiler Fuel Oil (2.3.3.5)	yes
Auxiliary Building (2.4.2.1)	yes
Auxiliary Building Auxiliary Steam	no
Auxiliary Building Fire Barriers	no
Auxiliary Building HVAC (2.3.3.11)	yes
Auxiliary Feedwater (2.3.4.2)	yes
NSR Auxiliary Feedwater Pump Fuel Oil *	no
Auxiliary Instrument Panel (2.5.15)	yes
Auxiliary Steam	no
Blowpipe System *	Yes[1]
Building Piles (2.4.2.4)	yes
Bus Bars (2.5.20)	yes

[1] System is included with Substation Equipment – SBO Restoration – RAI 2.5-1

TABLE 2.2-1 Plant Level Scoping Results	
SSC	Within Scope of License Renewal?
Cables and Connectors (2.5.1)	yes
Carbon Dioxide Gas *	no
Chem/RP Building HVAC	no
Chemical and Volume Control (2.3.3.1)	yes
Secondary Side Chemical Feed	no
Chemistry and Radiation Protection Building	no
Circulating Water	no
Communications (2.5.18)	yes
Component Cooling 2.3.3.16)	yes
Component Supports (2.4.2.6)	yes
Compressed Air	yes[1]
Condensate	no
Condensate Storage Tank Foundation *	no
Condenser Evacuation	no
Containment (2.4.1)	yes
Containment Electrical Penetrations (2.5.2)	yes
Containment Heating, Ventilation, and Air Conditioning (2.3.3.10)	yes
Containment Penetration, and System Interface comonents for Non-CQE Systems (2.3.2.2) *	yes
Control Board (2.5.16)	yes
Control Room Heating, Ventilation, and Air Conditioning (2.3.3.12)	yes
Demineralized Water *	yes[1]
Demineralized Water Sampling *	no
Diverse Scram System (2.5.17)	yes
Duct Banks (2.4.2.7)	yes
Electrical Equipment (2.5.14) *	yes

TABLE 2.2-1 Plant Level Scoping Results	
SSC	**Within Scope of License Renewal?**
Emergency Diesel Generator Fuel Oil (2.3.3.3)	yes
Emergency Diesel Generator Lube Oil and Fuel Oil (2.3.3.4)	yes
Emergency Diesel Jacket Water (2.3.3.6)	yes
Emergency Lighting (2.5.19)	yes
Engineered Safeguards (2.5.3)	yes
Feedwater (2.3.4.1)	yes
Fire Protection (2.3.3.14)	yes
Fire Protection - Security Building *	no
Fire Protection – Warehouse *	no
Fire Protection Fuel Oil (2.3.3.5)	yes
Fuel Handling Equipment and Heavy Load Cranes (2.4.2.5)	yes
Gaseous Waste Disposal (2.3.3.18)	yes
Gasoline Storage Tank	no
Generator Seal Oil *	no
Hazardous Waste Storage Building	no
Heater Vents and Drains *	no
Hydrogen Gas	no
Instrument Air (2.3.3.8)	yes
Intake and Turbine Building Sump Pump	no
Intake Structure (2.4.2.3)	yes
Intake Structure HVAC *	no
Liquid Waste Disposal (2.3.3.17)	yes
Main Steam and Turbine Steam Extraction (2.3.4.3)	yes
Maintenance Shop *	no
Meteorological Monitoring *	no
New Warehouse *	no

TABLE 2.2-1 Plant Level Scoping Results	
SSC	**Within Scope of License Renewal?**
Nitrogen Gas (2.3.3.9)	yes
Nitrous Oxide Gas *	no
Non-CQE Auxiliary Feedwater Pump Fuel Oil *	no
Nuclear Instrumentation (2.5.4)	yes
Oxygen Gas *	no
Plant Computer and Emergency Response Facility Computer (2.5.11)	yes
Plant Security *	no
Portal Monitor Gas *	no
Post Accident Sampling	no
Potable Water	no
Primary Sampling (2.3.3.19)	yes
Propane Gas *	no
Qualified Safety Parameter Display (2.5.12)	yes
Rad Waste Building	no
Rad Waste Building HVAC	no
Radiation Monitoring - Mechanical (2.3.3.20) Electrical (2.5.13)	yes
Raw Water (2.3.3.15)	yes
Reactor Coolant (2.3.1.2)	yes
Reactor Protection System (2.5.5)	yes
Reactor Regulating System	no
Reactor Vessel (2.3.1.3)	yes
Reactor Vessel Internals (2.3.1.1)	yes
Safety Injection (HPSI, LPSI, Containment Spray) (2.3.2.1)	yes
Sampling Platform *	no

TABLE 2.2-1 Plant Level Scoping Results	
SSC	**Within Scope of License Renewal?**
Sanitary and Storm Drains *	no
Seal Water	no
Secondary Sampling	no
Secondary Side Chemical Feed	no
Security Building *	no
Security Building HVAC *	no
Security Diesel *	no
Security Diesel Fuel Oil *	no
Service Air	no
Solid Waste Disposal	no
Spent Fuel Pool Cooling (2.3.3.2)	yes
Starting Air (2.3.3.7)	yes
Steam Generator ~~Feedwater~~ Blowdown	**~~no~~ yes**[1,2]
Substation *	no
Substation Equipment – **SBO Restoration (2.5.21)**	**~~no~~ yes**[3]
Technical Support Center	no
Technical Support Center HVAC	no
Toxic Gas Monitoring (2.3.3.12)	yes
Transformer Yard	no
Turbine Generator Electro Hydraulic Control *	no
Turbine Generator and Accessories	no
Turbine Generator Lubricating Oil	no
Turbine Building and Service Building (2.4.2.2)	yes
Turbine Building HVAC	no
Turbine Plant Cooling	**~~no~~ yes**[4]

[1] **POI-01(d)**
[3] **RAI 2.5-1/POI-06(a)**
[4] **POI-01(a)**

TABLE 2.2-1 Plant Level Scoping Results	
SSC	**Within Scope of License Renewal?**
Turbine Supervisory *	no
Vacuum Priming *	no
Vacuum Service (Laboratories) *	no
Ventilating Air (2.3.3.13)	yes
Vents and Drains	no
Vibration Monitoring	no
Warehouse HVAC	no

[1] The intended function(s) for these systems was limited to containment isolation and/or pressure boundary between CQE and Non-CQE systems. The number of components with intended functions in each of these systems is very small, so to make the process of evaluation and review more efficient the components which have intended functions were transferred to one commodity group for evaluation. That group is titled "Containment Penetration, and System Interface Components for Non-CQE Related Systems." (2.3.2.2)

TABLE 2.3.1.1-1
REACTOR VESSEL INTERNALS
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
CEA Shroud Bolts	Structure Functional Support	3.1.1.01 3.1.1.08 3.1.1.32 3.1.1.34 3.1.1.37
CSB Snubber Bolts	Structure Functional Support	3.1.1.01 3.1.1.08 3.1.1.32 3.1.1.34 3.1.1.37
Thermal Shield Bolts and Core Shroud Bolts	Structure Functional Support	3.1.1.08 3.1.1.32 3.1.1.34 3.1.1.37 3.1.3.01 3.1.3.02 3.1.3.03 3.1.3.04
CEA Shroud Spanner Nuts, and ICI Support Bolting	Structure Functional Support	3.1.1.01 3.1.1.08 3.1.1.32 3.1.1.34
CSB Bolts and Lower Internals Assembly Bolts	Structure Functional Support	3.1.1.01 3.1.1.08 3.1.1.32 3.1.1.34
CEA Shrouds, Base, Tube, and Transition Piece	Structure Functional Support	3.1.1.01 3.1.1.08 3.1.1.26 3.1.1.34
CSB, Core Support Ring	Structure Functional Support	3.1.1.01 3.1.1.08 3.1.1.32 3.1.1.34
CSB Alignment Key and CSB Upper Flange	Structure Functional Support	3.1.1.08 3.1.1.29 3.1.1.32 3.1.1.34
CSB Nozzle	Flow Distribution	3.1.1.01 3.1.1.08 3.1.1.32 3.1.1.34

TABLE 2.3.1.1-1
REACTOR VESSEL INTERNALS
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
CSB - Spacer, Locking Collar, Dowel Pin, and Locking Bar	Structure Functional Support	3.1.1.08 3.1.1.32 3.1.1.34
CSB Snubber Spacer Block	Structure Functional Support	*3.1.1.01* 3.1.1.08 3.1.1.29 3.1.1.32 3.1.1.34
Core Shroud	Structure Functional Support	3.1.1.01 3.1.1.08 3.1.1.32 3.1.1.34
Flow Skirt	Flow Distribution	3.1.2.08 3.1.2.09 3.1.2.10 3.1.2.11
Fuel Assembly Alignment Plate	Structure Functional Support	3.1.1.08 3.1.1.29 3.1.1.34
ICI Guide Tube & Supports	Structure Functional Support	~~*3.1.1.01*~~ 3.1.1.08 3.1.1.34
ICI Support Plate & Gusset	Structure Functional Support	*3.1.1.01* 3.1.1.08 3.1.1.34
Instrument Tube & Supports	Structure Functional Support	*3.1.1.01* 3.1.1.08 3.1.1.34
Lower Internals Assembly - Manhole Cover Plate & Bottom Plate	Structure Functional Support	3.1.1.08 3.1.1.32 3.1.1.34
Lower Internals Assembly - Core Support Columns	Structure Functional Support	3.1.1.01 3.1.1.08 3.1.1.26 3.1.1.34
Lower Internals Assembly - Core Support Plate and Support Beams and Flanges	Structure Functional Support	3.1.1.01 3.1.1.08 3.1.1.32 3.1.1.34
Lower Internals Assembly - Anchor Block and Dowel Pins	Structure Functional Support	3.1.1.08 3.1.1.32 3.1.1.34

TABLE 2.3.1.1-1
REACTOR VESSEL INTERNALS
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
Thermal Shield	Radiation Shielding	~~*3.1.1.01*~~ *3.1.3.01* 3.1.3.02 3.1.3.04 3.1.3.05 3.1.3.14
Thermal Shield – Positioning Pin & Shim	Structure Functional Support	~~*3.1.1.01*~~ *3.1.1.08* *3.1.3.01* 3.1.3.02 3.1.3.03 3.1.3.04
UGS - Ring Shim, Tab, & Plate	Structure Functional Support	3.1.1.08 3.1.1.34
UGS - Dowel Pin& Locking Strip	Structure Functional Support	3.1.1.08 3.1.1.34
UGS - Guide Pin	Structure Functional Support	3.1.1.08 3.1.1.29 3.1.1.34
UGS - Alignment Lug	Structure Functional Support	3.1.1.08 3.1.1.29 3.1.1.34
UGS - Alignment Lug Screw and Nut	Structure Functional Support	3.1.1.08 3.1.1.34
UGS - Key Slot Tab	Structure Functional Support	3.1.1.08 3.1.1.34
UGS - Hold-down Ring	Structure Functional Support	3.1.1.08 3.1.1.29 3.1.1.34
UGS - Support Plate & Sleeves	Structure Functional Support	3.1.1.08 3.1.1.29 3.1.1.34

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.3.1.2-1
REACTOR COOLANT
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
Bolting	Pressure Boundary/Fission Product Retention	3.1.1.23 3.1.1.27 3.2.1.11 3.2.1.12 3.1.2.12
Flow Element/ Orifice	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.06 3.1.2.01
Pressurizer Bottom Plate (Cladding)	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.25
Pressurizer Heater Sleeves	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.11 3.1.2.02
Pressurizer Heater Support Assembly	Component Structural Support	3.1.1.01 3.1.1.25
Pressurizer Manway	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.25 3.1.1.27 3.1.2.13 3.1.2.01
Pressurizer RV Nozzle Insert and Pressurizer Upper and Lower Level Instrument Nozzle Inserts	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.2.16
Pressurizer Relief Valve and Upper & Lower Level Instrument Nozzles	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.27
Pressurizer RV, Spray, Surge, SV, and Upper & Lower Level Instrument Nozzle Welds	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.11 3.1.2.02 3.1.2.03
Pressurizer PORV, Spray, Surge, Temperature, and Upper & Lower Level Nozzle Safe Ends	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.11 3.1.1.25 3.1.2.01 3.1.2.02 3.1.2.03
Pressurizer Shell	Pressure Boundary/ Fission Product Retention	3.1.3.11
Pressurizer Shell (Cladding)	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.25
Pressurizer Spray and Surge Nozzle Thermal Sleeves	Fatigue Prevention	3.1.1.01 3.1.1.11 ~~3.1.1.25~~ 3.1.2.02

TABLE 2.3.1.2-1
REACTOR COOLANT
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
Pressurizer Spray, Surge, and Safety Valve Nozzles (Base)	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.10 3.1.1.21
Pressurizer Spray, Surge, and Safety Valve Nozzles . (Cladding)	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.25
Pressurizer Support Assembly	Component Structural Support	3.1.1.27 3.1.2.15
Pressurizer Safety Valve Nozzle Flange and Temperature Nozzle	Pressure Boundary/ Fission Product Retention	3.1.2.03
Pressurizer Vessel Welds	Pressure Boundary/ Fission Product Retention	*3.1.2.15*
RC Hot & Cold Leg Piping	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.10 3.1.1.21 3.1.2.01
RC Piping Charging, Drain, Pressure Measurement, Pressure Measurement & Sampling, Shutdown Cooling Inlet and Outlet Spray, Gas Vent and Surge Line	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.06 3.1.1.25 3.1.2.01
RC Piping Nozzle Thermal Sleeves (Charging, SDC Inlet and Surge)	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.25
RC Piping Nozzles (Charging, Drain, Pressure Measurement, Pressure Measurement and Sampling, SDC inlet, SDC Outlet, Spray, Surge)	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.10 3.1.1.21 3.1.2.01
RC Piping Thermowells and Stainless Steel Welds (All NPS)	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.06 3.1.1.25
RC Piping Welds (A182/82)	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.11 3.1.2.02 3.1.2.03
RCP Driver Mounts	Pressure Boundary/ Fission Product Retention	3.1.3.09
RCP Pump Cover (Thermal Barrier)	Pressure Boundary/ Fission Product Retention	3.1.1.25 3.1.2.01 3.1.2.05 3.2.1.09 3.3.2.74

TABLE 2.3.1.2-1
REACTOR COOLANT
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
RCP Seal Cover and Bleed-off Flange	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.25 3.1.2.01
RCP Seal Water Cooler Tubes	Pressure Boundary/ Fission Product Retention	3.1.1.01 ~~3.1.1.25~~ *3.3.3.01* 3.2.1.09 3.3.2.74
Reactor Coolant Pump Casing	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.20 3.1.1.25
Steam Generator FW Nozzle Safe End	Pressure Boundary	3.1.1.01 3.1.1.22 3.1.2.06 3.1.2.13 3.1.3.08
Steam Generator Feedwater Feed Ring	Flow Distribution	3.1.1.01 3.1.2.14
Steam Generator FW, Primary, Instrument, and Steam Nozzles	Pressure Boundary	3.1.1.01 3.1.1.27 3.1.2.06 3.1.3.12
Steam Generator Nozzle Welds	Pressure Boundary	3.1.1.01 3.1.1.11 3.1.2.02
Steam Generator Primary Head and Manway (Base)	Pressure Boundary	3.1.1.27
Steam Generator Primary Head (Cladding)	Pressure Boundary/ Fission Product Retention	3.1.1.01 **~~3.1.2.04~~ 3.1.1.33**[5]
Steam Generator Primary Manways (Cladding)	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.33 3.1.2.04
Steam Generator Primary Nozzle (Cladding)	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.33
Steam Generator Primary Nozzle Safe End	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.33 3.1.2.01
Steam Generator Secondary Head, Shell, and Transition Cone	Pressure Boundary	3.1.1.01 3.1.1.02 3.1.1.27
Steam Generator Secondary Manways and Handholes	Pressure Boundary	3.1.1.01 3.1.1.02

[5] **RAI # 3.1.2-1**

TABLE 2.3.1.2-1 REACTOR COOLANT Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Steam Generator Steam Nozzle Safe End	Pressure Boundary	3.1.1.01 3.1.1.22 3.1.2.13 3.1.2.14
Steam Generator Tube Plugs	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.15 **~~3.1.2.07~~**[6]
Steam Generator Tube Sheet(Primary Side)	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.2.04
Steam Generator Tube Sheet(Secondary Side)	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.2.06
Steam Generator Tube Supports	Structure Functional Support	3.1.1.01 3.1.1.16 3.1.1.17
Steam Generator Blowdown Nozzles	Pressure Boundary	3.1.1.01 **3.1.2.06**[7] **~~3.4.1.02~~**[3] 3.4.1.06 **~~3.4.1.05~~**[3] 3.4.1.13
Steam Generator Tubes	Heat Transfer Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.15
Valve Bodies	Pressure Boundary/ Fission Product Retention	3.1.1.01 3.1.1.20 3.1.1.25 3.1.1.27 3.1.3.06 3.1.3.10 3.1.2.01

Red & Italics – Review based changes
Blue & Bold – RAI based changes

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[6] **RAI # B.2.9-2**
[7] **RAI # 3.1-1**

TABLE 2.3.1.3-1
REACTOR VESSEL
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
Closure Studs, CEDM Housing Studs and ICI Studs	Pressure Boundary/Fission Product Retention	3.1.1.01 3.1.1.19 3.1.1.23 3.1.1.27 3.1.1.36
CEDM Nozzles	Pressure Boundary/Fission Product Retention	3.1.1.01 3.1.1.24 3.1.2.02 3.1.2.03
Core Stabilizing Lugs	Limit Vibration	3.1.1.01 3.1.1.09 3.1.2.02
Core Support Lugs	Core Displacement	3.1.1.01 3.1.1.09 3.1.2.02
ICI and RC Vent Nozzles	Pressure Boundary/Fission Product Retention	3.1.1.01 3.1.3.13 3.1.2.02 3.1.2.03
Keyways and Core Barrel Support Ledge	Structural Support	3.1.1.01 3.1.1.~~25~~ *09*
Pipes & Fittings, CEDM Housing	Pressure Boundary/Fission Product Retention ***Heat Transfer***[8]	3.1.1.01 3.1.1.06 3.1.1.24 3.1.1.25 3.1.2.01 3.1.2.03 **3.3.3.13**[4] **3.3.3.15**[4]
Primary Nozzle Supports	Structural Support	3.1.1.27
RV Closure Head Lift Rig Pads	Structural Support	3.1.1.27
RV Closure Head, RV Lower Shell, RV Middle Shell, RV Bottom Head, RV Flange and associated cladding	Pressure Boundary/Fission Product Retention	3.1.1.01 3.1.1.03 3.1.1.04 3.1.1.09 3.1.1.25 3.1.1.27 3.1.1.29 3.1.2.02
RV Nozzle Safe Ends	Pressure Boundary/Fission Product Retention	3.1.1.01 3.1.1.25 3.1.2.01

[8] **RAI # 2.3.3.16-2**

TABLE 2.3.1.3-1 REACTOR VESSEL Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
RV Nozzles and associated cladding	Pressure Boundary/Fission Product Retention	3.1.1.01 3.1.1.03 3.1.1.25 3.1.1.27
Surveillance Capsule Holders	Non-Safety Affecting Safety	3.1.1.01 3.1.1.09 3.1.2.02

Red & Italics – Review based changes
Blue & Bold – RAI based changes

TABLE 2.3.2.1-1 SAFETY INJECTION AND CONTAINMENT SPRAY Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Leakage Accumulators	Pressure Boundary/Fission Product Retention	3.2.3.02 3.2.1.11
Bolting	Pressure Boundary/Fission Product Retention	3.2.1.11 3.2.1.12 3.2.2.04
Filter/strainer	Filtration Pressure Boundary/Fission Product Retention	3.2.2.05
Flow Element/orifice	Pressure Boundary/Fission Product Retention	3.2.1.01 3.2.2.04 3.2.3.01
Heat Exchanger	Pressure Boundary/Fission Product Retention	*~~3.2.1.01~~* 3.2.1.09 3.2.1.11 3.2.2.01 3.2.2.02 3.2.2.03 3.2.2.04 3.2.2.06 3.2.3.01 3.3.2.74
Orifice Plate	Flow Restriction Pressure Boundary/Fission Product Retention	3.2.2.04 3.2.3.01
Pipes & Fittings	Pressure Boundary/Fission Product Retention	3.2.1.01 3.2.1.10 3.2.2.04 3.3.2.10 *~~3.3.2.17~~* *~~3.3.2.18~~*
Pump Casings	Pressure Boundary/Fission Product Retention	3.2.1.10 3.2.2.04
Injection Tanks	Pressure Boundary/Fission Product Retention	3.2.2.04 3.2.3.01
Tubing	Pressure Boundary/Fission Product Retention	3.2.3.01 3.2.2.04
Valve Bodies	Pressure Boundary/Fission Product Retention	3.2.1.01 3.2.1.10 3.2.2.04 *~~3.2.2.07~~*

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.3.2.2-1
CONTAINMENT PENETRATIONS, AND SYSTEM INTERFACE
Component Types Subject to Aging Management
Review and Intended Functions

Component Type	Intended Functions	AMR Results
Bolting	Pressure Boundary	3.2.1.12
Heat Exchanger	Pressure Boundary	3.4.1.10 3.2.2.04 *3.3.2.74* 3.3.2.76
Pipes & Fittings	Pressure Boundary	3.2.1.03 3.2.1.04 3.2.1.06 3.2.1.11 3.4.1.02 3.4.1.05 3.4.1.06 3.4.1.13 3.2.2.04 3.2.2.07 **3.3.2.78**[9]
Primary Containment Penetrations	Pressure Boundary	3.2.1.06 3.2.1.11 3.2.2.04 *3.2.2.07*
Valve Bodies	Pressure Boundary	3.2-1.03 3.2-1.04 3.2-1.06 3.2-1.11 3.4-1.02 3.4-1.05 3.4-1.06 3.4-1.13 3.2.2.04 *3.2.2.07* **3.3.2.78**[5]

Red & Italics – Review based changes
Blue & Bold – RAI based changes

[9] **RAI # 2.3.3.8-1**

TABLE 2.3.3.1-1 CHEMICAL AND VOLUME CONTROL SYSTEM Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Bolting	Pressure Boundary	3.3.1.13 3.3.1.23 3.3.2.~~64~~*75*
Filter/strainer Housing	Pressure Boundary	3.3.1.03 **~~3.3.1.08~~ 3.3.3.01**[10] 3.3.2.~~64~~*75*
Flow Element/orifice	Pressure Boundary	~~*3.3.1.03*~~ **~~3.3.1.08~~ 3.3.3.01**[6] 3.3.2.50 3.3.2.~~64~~*75*
Heat Exchanger	Pressure Boundary	3.3.1.03 3.3.1.05 3.3.1.08 3.3.1.13 3.3.1.14 **~~3.4.1.10~~**[11] 3.3.2.10 3.3.2.16 3.3.2.17 3.3.2.18 3.3.2.~~64~~*75*
Ion Exchangers	Pressure Boundary	~~*3.3.1.03*~~ **~~3.3.1.08~~ 3.3.3.01**[6] 3.3.2.~~64~~*75*
Pipes, Fittings & Tubing	Pressure Boundary	3.3.1.03 **~~3.3.3.04~~**[12] 3.3.1.05 **~~3.3.1.08~~ 3.3.3.01**[6] 3.3.1.13 3.3.2.50 *3.3.2.70* 3.3.2.~~64~~*75* 3.3.3.03 3.3.3.24

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[10] RAI # 3.3.1-15
[11] RAI # 3.3-1
[12] RAI # 3.3.3-3

TABLE 2.3.3.1-1 CHEMICAL AND VOLUME CONTROL SYSTEM Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Pump Casings	Pressure Boundary	3.3.1.03 3.3.1.04 3.3.2.50 3.3.2.~~*64*~~*75*
Tanks	Pressure Boundary	3.3.1.03 **~~3.3.1.08~~**[6] 3.3.2.50 3.3.2.~~*64*~~*75* **3.3.3.01**[6]
Transmitter/Element	*Pressure Boundary*	*3.3.1.03* *3.3.3.01* *3.3.2.75*
Valve Bodies	Pressure Boundary	3.3.1.03 3.3.1.05 **~~3.3.1.08~~ 3.3.3.01**[6,8] 3.3.1.13 3.1.1.25 **~~3.4.1.02~~ 3.3.3.03**[7] 3.3.2.50 3.3.2.~~*-64*~~*75* 3.3.2.70 3.3.2.82 3.3.3.03 **~~3.3.3.04~~**[8] *3.3.3.07* *3.3.3.09*

Red & Italics – Review based changes
Blue & Bold – RAI based changes

TABLE 2.3.3.2-1
SPENT FUEL POOL COOLING
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
Bolting	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.2.~~*64*~~ *75*
Filter/strainer Housing	Pressure Boundary	~~**3.2.1.10**~~ **3.3.3.01**[13] 3.3.2.~~*64*~~ *75*
Heat Exchanger	Heat Transfer Pressure Boundary	*3.3.1.05* ~~*3.3.1.08*~~ 3.3.1.13 ~~*3.3.1.14*~~ ~~**3.2.1.10**~~ **3.3.3.01**[9] ~~**3.4.1.10**~~ **3.2.1.09**[9] *3.3.2.74* 3.3.2.~~*64*~~ *75*
Ion Exchangers	Pressure Boundary	~~**3.2.1.10**~~ **3.3.3.01**[9] 3.3.2.~~*64*~~ *75*
Pipes & Fittings	Pressure Boundary	~~**3.2.1.10**~~ **3.3.3.01**[9] 3.3.2.~~*64*~~ *75*
Pump Casings	Pressure Boundary	~~**3.2.1.10**~~ **3.3.3.01**[9] 3.3.2.~~*64*~~ *75*
Valve Bodies	Pressure Boundary	~~**3.2.1.10**~~ **3.3.3.01**[9] 3.3.2.~~*64*~~ *75*

Red & Italics – Review based changes
Blue & Bold – RAI based changes

[13] **RAI # 3.3-1**

TABLE 2.3.3.3-1 EMERGENCY DIESEL GENERATORS Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Bolting	Pressure Boundary/structural integrity	3.3.1.05
Pipes & Fittings	Provides an exhaust path for diesel generators	3.3.1.05 3.3.2.46 3.3.2.~~*64*~~ *75* 3.3.2.69 3.3.2.83
Mechanical Function Unit	*Provide shelter/protection to safety-related component*	*3.3.1.05* *3.3.2.46*

Red & Italics– Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.3.3.4-1 EMERGENCY DIESEL GENERATOR LUBE OIL AND FUEL OIL Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Bolting	Pressure Boundary Filtration	3.3.1.05 3.3.2.~~64~~ *75*
Filters/strainers	Pressure Boundary	3.3.1.05 3.3.1.07 3.3.3.05 3.3.3.06 3.3.2.40
Flow Element/orifice	Pressure Boundary	3.3.1.05 3.3.3.05
Heat Exchanger	Heat Transfer Pressure Boundary	3.3.1.05 3.3.3.05 3.3.2.39 3.3.2.41 3.3.2.84 3.3.2.85
Hose	Pressure Boundary	~~*3.3.3.05*~~ ~~*3.3.1.05*~~ *These components will be replaced on performance or condition in accordance with the Periodic Surveillance and Preventive Maintenance Program.*
Hose Coupling	Pressure Boundary	~~*3.3.3.05*~~ ~~*3.3.1.05*~~ *These components will be replaced on performance or condition in accordance with the Periodic Surveillance and Preventive Maintenance Program.*
Indicator/recorder (sightglass)	Pressure Boundary	3.3.2.49
Pipes & Fittings	Pressure Boundary	3.3.1.05 3.3.3.06 3.3.3.05 3.3.2.32 3.3.2.86
Pump Casings	Pressure Boundary	3.3.1.05 3.3.2.87 3.3.2.88 *3.3.3.07*

TABLE 2.3.3.4-1 EMERGENCY DIESEL GENERATOR LUBE OIL AND FUEL OIL Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Tanks	Pressure Boundary	3.3.1.05 3.3.1.07 *3.3.2.32* 3.3.2.86 3.3.2.89
Tubing	Pressure Boundary	3.3.2.~~*64*~~ *75* 3.3.2.68
Valve Bodies	Pressure Boundary	3.3.1.05 3.3.2.10 3.3.2.11 3.3.2.32 3.3.2.~~*64*~~ *75* 3.3.2.85 3.3.2.89 3.3.3.06 3.3.3.07

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.3.3.5-1 AUXILIARY BOILER FUEL OIL AND FIRE PROTECTION FUEL OIL Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Bolting	Pressure Boundary	3.3.1.05
Filters/strainers	Filtration Pressure Boundary	3.3.1.05 3.3.2.01 3.3.2.02 3.3.3.06 3.3.2.10 3.3.2.11 3.3.2.32
Hose	Pressure Boundary	These components will be replaced on performance or condition in accordance with the Periodic Surveillance and Preventive Maintenance Program.
Hose Coupling	Pressure Boundary	These components will be replaced on performance or condition in accordance with the Periodic Surveillance and Preventive Maintenance Program.
Indicator/recorder (sightglass)	Pressure Boundary	3.3.2.49
Pipes & Fittings	Pressure Boundary	3.3.1.05 3.3.1.17 3.3.1.21 3.3.3.06 3.3.2.21 3.3.2.32 3.3.2.47 3.3.2.48
Pump Casings	Pressure Boundary	3.3.2.10 3.3.2.11 3.3.2.32 *3.3.2.87* ~~*3.3.3.06*~~ 3.3.3.07

TABLE 2.3.3.5-1 AUXILIARY BOILER FUEL OIL AND FIRE PROTECTION FUEL OIL Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Tanks	Pressure Boundary	3.3.1.05 3.3.1.07 ~~*3.3.3.06*~~ 3.3.2.21 3.3.2.32 *3.3.2.86*
Tubing	Pressure Boundary	3.3.2.37 3.3.2.40 3.3.2.42 3.3.2.43 3.3.2.44 3.3.2.45
Valve Bodies	Pressure Boundary	3.3.1.05 3.3.2.01 3.3.2.02 3.3.3.06 3.3.2.10 3.3.2.11 3.3.2.32 3.3.2.~~*64*~~ *75*

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.3.3.6-1
EMERGENCY DIESEL GENERATOR JACKET WATER
Component Types Subject to Aging Management
Review and Intended Functions

Component Type	Intended Functions	AMR Results
Bolting	Pressure Boundary	3.3.1.05
Electric Heaters	Pressure Boundary	3.3.1.05 3.3.3.08
Heat Exchangers (radiators)	Pressure Boundary Heat Transfer	3.3.1.05 3.3.3.08 3.3.2.39 3.3.2.41 3.3.2.84
Indicator/recorder (sightglass)	Pressure Boundary	3.3.2.49
Pipes & Fittings	Pressure Boundary	3.3.1.05 3.3.1.14 3.3.2.29 *3.3.2.30* 3.3.2.~~64~~ *75* 3.3.2.74 3.3.3.07 3.3.3.15
Pump Casings	Pressure Boundary	~~*3.3.1.05*~~ *3.3.3.07* 3.3.1.13 3.3.2.29 3.3.2.30
Tanks	Pressure Boundary	3.3.1.05 3.3.3.08
Valve Bodies	Pressure Boundary	3.3.1.05 3.3.1.14 3.3.2.29 3.3.2.30 3.3.2.39 3.3.2.40 3.3.2.41 3.3.2.84 3.3.3.07

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.3.3.7-1 STARTING AIR Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Bolting	Pressure Boundary	3.3.1.05 3.3.2.~~64~~ *75*
Filters/strainers	Filtration Pressure Boundary	3.3.1.05 3.3.2.23
Heat Exchangers	Heat Transfer Pressure Boundary	3.3.1.05 3.3.2.23
Lubricator Body	Pressure Boundary	3.3.1.05 3.3.2.23
Air Motor Casings	Pressure Boundary	3.3.1.05 3.3.2.23
Pipes & Fittings	Pressure Boundary	3.3.1.05 3.3.2.23 3.3.2.37 3.3.2.40 3.3.2.71 3.3.2.75
Tanks	Pressure Boundary	3.3.1.05 3.3.2.23
Valve Bodies	Pressure Boundary	3.3.1.05 3.3.2.10 3.3.2.13 3.3.2.20 3.3.2.23 3.3.2.37 3.3.2.40 3.3.2.71 3.3.2.75 3.3.3.07

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.3.3.8-1
INSTRUMENT AIR
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
Accumulators	Pressure Boundary	3.3.1.0~~7~~ *5* 3.3.1.13 3.3.2.23 3.3.2.25
Bolting	Pressure Boundary	3.3.1.05 3.3.1.13
Filter Housing	Pressure Boundary	3.3.2.01 3.3.2.04
Pipes & Fittings	Pressure Boundary	3.3.2.71 3.3.2.75
Tubing	Pressure Boundary	3.3.2.37 3.3.2.40 3.3.2.71 3.3.2.72 3.3.2.7~~1~~ *5*
Valve Body	Pressure Boundary	3.3.2.01 3.3.2.04 3.3.2.05 3.3.2.10 3.3.2.13 3.3.2.14 3.3.2.71 3.3.2.72 3.3.2.7~~1~~ *5*
Valve Operator Bodies	Pressure Boundary	3.3.2.01 3.3.2.04 3.3.1.05 3.3.1.13 3.3.2.23

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.3.3.10-1 CONTAINMENT VENTILATION Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Blowers & Fan Housing	Pressure Boundary	3.3.1.05 3.1.3.13 3.3.3.07 3.3.2.90
Bolting	Pressure Boundary	3.3.1.05 3.1.3.13 3.3.2.75 *3.3.3.09*
Filter Housing	Pressure Boundary	3.3.1.05 3.3.3.09
Duct	Pressure Boundary	3.3.1.02 3.3.1.05 *~~3.1.3.13~~ 3.3.3.09*
Dampers	Pressure Boundary	3.3.1.05 *~~3.1.3.13~~ 3.3.3.09*
Heat Exchangers	Heat Transfer	3.3.1.05 **3.3.2.01**[14] 3.3.2.10 *3.3.2.17* 3.3.2.39 *3.3.2.84* *~~3.3.3.09~~*
Valve Bodies	Pressure Boundary/Fission Product Retention	3.3.1.05 3.3.1.13 3.3.2.10 3.3.2.75 3.3.3.07 3.3.3.09 *3.3.3.10*
Pipes and fittings	Pressure Boundary	3.3.1.05 **~~3.1.3.13~~ 3.3.1.13**[15] 3.3.2.75
~~Valve operators~~	**~~Pressure Boundary~~**	**~~3.3.1.05~~**[10] **~~3.1.3.13~~**[10]

Red & Italics – Review based changes
Blue & Bold – RAI based changes

[14] **RAI # 2.3.3.10-1**
[15] **RAI # 3.3-1**

TABLE 2.3.3.11-1 AUXILIARY BUILDING HVAC Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Blower & Fan Housings	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.2.01 *3.3.3.09*
Bolting	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.2.75 *3.3.3.09*
Filter/strainer Housing	Pressure Boundary Pressure Boundary/Fission Product Retention	3.3.1.05 3.3.1.13 *3.3.3.09*
Fire Blocking Damper	Fire Barrier	3.3.2.75 3.3.3.10
Flow Element Housing	*Pressure Boundary*	*3.3.1.05* *3.3.3.09*
Duct	Pressure Boundary	*3.3.1.05* 3.3.1.02 ~~*3.3.2.48*~~ 3.3.3.09 ~~*3.3.3.10*~~
Dampers	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.2.01 3.3.3.07 3.3.3.09 3.3.3.10
Pipes & Fittings	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.2.75
Valve Bodies	Pressure Boundary	*3.3.1.05* 3.3.3.07 3.3.3.09 3.3.3.10

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.3.3.12-1
CONTROL ROOM HVAC AND TOXIC GAS MONITORING
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
Blower & Fan Housing	Pressure Boundary	3.3.1.05 3.3.3.07 3.3.3.10
Bolting	Pressure Boundary	3.3.1.05 3.3.3.07 3.3.2.75
Duct	Pressure Boundary	3.3.1.02 3.3.1.05 3.3.3.07 3.3.3.10
Filter/strainer	Pressure Boundary	3.3.1.05 3.3.2.75
Fire Blocking Damper	*Fire Barrier*	*3.3.3.10*
Heat Exchanger	Pressure Boundary Heat Transfer	3.3.1.05 3.3.2.29 *3.3.2.30* 3.3.2.39 3.3.2.40 *3.3.3.10*
Pipes & Fittings	Pressure Boundary	3.3.1.05 3.3.1.14 3.3.2.38 3.3.2.40 3.3.2.75 ~~*3.3.2.91*~~
Valve Bodies	Pressure Boundary	3.3.1.05 3.3.2.01 3.3.2.10 3.3.2.15 3.3.2.28 3.3.2.29 *3.3.2.30* 3.3.2.38 *3.3.2.40* 3.3.2.75 3.3.3.07

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.3.3.14-1
FIRE PROTECTION
Component Types Subject to Aging Management
Review and Intended Functions

Component Type	Intended Functions	AMR Results
Bolting	Pressure Boundary	3.3.1.05 *3.3.1.13* 3.3.1.20 3.3.2.40 3.3.2.75 3.3.2.92
Filters/strainers	Filtration Pressure Boundary	**3.3.1.05**[16] **3.3.1.11**[12] *3.3.1.13* 3.3.1.20 3.3.2.40 3.3.2.93 **3.3.3.11**[12]
Flow Element/Orifice	Pressure Boundary	3.3.1.20 3.3.2.40 **3.3.3.11**[12]
FP Sprinkler/Spray Nozzle	Pressure Boundary	3.3.1.20 3.3.2.40 **3.3.3.11**[12]
Halon System Nozzle	Flow Restriction/Spray Pattern	3.3.2.01
Hose	Pressure Boundary	Fire hoses are not subject to an aging management review because they are replaced based on condition in accordance with applicable NFPA standards and plant procedures for fire protection equipment.
Hose Cabinet	Fire Hose Support	3.3.1.05 3.3.1.13

[16] **RAI # 2.3.3.14-2**

TABLE 2.3.3.14-1
FIRE PROTECTION
Component Types Subject to Aging Management
Review and Intended Functions

Component Type	Intended Functions	AMR Results
Pipes & Fittings	Pressure Boundary	3.3.1.05 *3.3.1.13* ~~*3.3.1.06*~~ 3.3.1.20 **3.3.2.27**[12] 3.3.2.31 3.3.2.34 3.3.2.35 3.3.2.40 **3.3.2.47**[12] 3.3.2.48 3.3.2.~~*64*~~ *75* 3.3.2.73 3.3.2.94 **3.3.3.11**[12]
Piping Spray Shield	Provide shelter/protection to safety-related components	3.3.1.05 3.3.1.13 3.3.2.73 3.3.2.75
Pressure Vessels	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.2.33 ~~*3.3.2.73*~~ ~~*3.3.2.75*~~
Pump Casings	Pressure Boundary	*3.3.1.05* 3.3.1.20 **3.3.2.27**[12] **3.3.2.30**[12] **3.3.2.93**[12] **3.3.3.11**[12]
Switch/bistable Housing	Pressure Boundary	3.3.2.01 3.3.2.06 3.3.2.~~10~~ **40**[12] 3.3.2.19 **3.3.3.11**[12]
Tank	*Pressure Boundary*	**3.3.1.20**[12] *3.3.2.73* **3.3.2.75**[12]

TABLE 2.3.3.14-1 FIRE PROTECTION Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Valve Bodies	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.1.20 **3.3.2.03**[12] ~~*3.3.2.10*~~ 3.3.2.12 **3.3.2.30**[12] 3.3.2.31 3.3.2.40 3.3.2.73 3.3.2.75 3.3.2.93 **3.3.2.95**[12] **3.3.3.11**[12]

Red & Italics – Review based changes
Blue & Bold – RAI based changes

TABLE 2.3.3.15-1 RAW WATER Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Bolting	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.1.16 3.3.2.75
Filters/strainers	Filtration Pressure Boundary	~~3.3.1.05~~ *3.3.3.07* 3.3.2.75 ~~3.3.2.77~~[17] 3.3.3.11 3.3.1.16
Flow Element/orifice	Pressure Boundary	3.3.1.16 3.3.2.75
Heat Exchanger	Heat Transfer Pressure Boundary	3.3.1.05 3.3.1.13 3.3.1.16 3.3.3.08 3.3.3.12 3.3.3.13
Indicator/recorder (sight glass)	Pressure Boundary	3.3.2.62 3.3.2.63 3.3.2.~~64~~ *75* 3.3.3.12
Orifice Plate	Flow Restriction Pressure Boundary	3.3.1.16 3.3.2.~~64~~ *75*
Pipes & Fittings	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.1.16 3.3.1.17 3.3.2.~~64~~ *75*
Pump Casing	Pressure Boundary	3.3.1.16 3.3.3.12
Traveling Screen Frame	Structural Support	~~3.3-2.95~~ 3.3.3.14

[17] **RAI # 3.3.2-1**

TABLE 2.3.3.15-1
RAW WATER
Component Types Subject to Aging Management
Review and Intended Functions

Component Type	Intended Functions	AMR Results
Valve Bodies	Pressure Boundary	*3.3.1.05* *3.3.1.13* 3.3.1.16 *3.3.3.07* *3.3.3.09* *~~3.3.3.10~~* 3.3.3.11 3.3.2.76 3.3.2.75

Red & Italics – Review based changes
Blue & Bold – RAI based changes

TABLE 2.3.3.16-1
COMPONENT COOLING
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
Accumulators	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.1.14
Bolting	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.2.~~64~~*75*
Flow Element/orifice	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.1.14 3.3.2.~~64~~ *75* 3.3.2.74
Heat Exchanger	Pressure Boundary	3.3.1.05 3.3.3.08 3.3.1.13 3.3.2.17 3.3.2.18 ~~3.3.2.41~~ 3.3.2.57 3.3.2.89
Indicator/recorder (sight glass)	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.2.49 3.3.2.74 3.3.2.75 3.3.3.08 3.3.3.15
Pipes & Fittings	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.1.14 3.3.2.~~64~~ *75* 3.3.2.74 3.3.3.15
Pump Casings	Pressure Boundary	3.3.1.14 3.3.1.24 3.3.3.07 3.3.3.09

TABLE 2.3.3.16-1
COMPONENT COOLING
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
Valve Bodies	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.1.14 *3.3.2.25* 3.3.2.~~64~~ *75* 3.3.2.74

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.3.3.17-1 LIQUID WASTE DISPOSAL Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Bolting	**~~Pressure~~ Fluid Boundary** **~~Water Suppression Support~~**[18]	3.3.1.05 3.3.1.13 3.3.2.75
Pipes & Fittings	**~~Pressure~~ Fluid Boundary** **~~Water Suppression Support~~**[14]	3.3.1.05 3.3.1.13 *~~3.3.2.22~~* 3.3.2.26 3.3.2.*~~64~~ 75* 3.3.2.65 3.3.2.96
Valve Bodies	**~~Pressure~~ Fluid Boundary** **~~Water Suppression Support~~**[14]	3.3.1.05 3.3.1.13 3.3.2.26 *~~3.3.2.64~~* 3.3.2.75 3.3.2.96
~~Pump Casing~~	**~~Pressure Boundary~~** **~~Water Suppression Support~~**	**~~3.3.1.05~~**[19] **~~3.3.1.13~~**

Red & Italics – Review based changes
Blue & Bold – RAI/POI based changes

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[18] POI-10(d)
[19] RAI # 3.3.1-12

TABLE 2.3.3.18-1 GASEOUS WASTE DISPOSAL Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Bolting	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.2.~~*64*~~ *75*
Heat Exchanger	Pressure Boundary	3.3.1.05 3.3.1.13 3.3.2.27 3.3.2.74 3.3.2.76 3.3.3.08 3.3.3.15
Pipes & Fittings	Gaseous Discharge Path Pressure Boundary/Fission Product Retention	3.3.1.05 3.3.1.13 3.3.2.25 3.3.2.~~*64*~~ *75* 3.3.2.72
Valve Bodies	Gaseous Discharge Path Pressure Boundary Pressure Boundary/Fission Product Retention	3.3.1.05 3.3.1.13 3.3.2.25 3.3.2.~~*64*~~ *75* 3.3.2.72

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.3.3.19-1 PRIMARY SAMPLING Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Bolting	Pressure Boundary/Fission Product Retention	3.3.1.23 3.3.2.75
Heat Exchanger	Pressure Boundary **~~Heat Transfer~~**[20]	*~~3.3.1.03~~* *3.2.1.09* 3.3.1.05 3.3.1.13 3.4.1.10 *~~3.3.2.18~~* 3.3.2.38 *3.3.2.39* *~~3.3.2.41~~* 3.3.2.55 3.3.2.56 3.3.2.57 3.3.2.58 3.3.2.74 3.3.3.01 *~~3.3.3.08~~*
Pipes & Fittings	Pressure Boundary/Fission Product Retention	3.1.1.01 3.3.2.*~~64~~ 75* 3.3.2.66 3.3.2.67 3.3.3.01
Valve Bodies	Pressure Boundary/Fission Product Retention	3.1.1.01 3.3.2.*~~64~~ 75* 3.3.2.66 3.3.2.67 3.3.3.01

Red & Italics – Review based changes
Blue & Bold – RAI based changes

[20] **RAI # 2.3.3.19-1**

TABLE 2.3.3.20-1
RADIATION MONITORING - MECHANICAL
Component Types Subject to Aging Management Review and Intended Functions

Component Type	**Intended Functions**	**AMR Results**
Bolting	Pressure Boundary/Fission Product Retention	3.3.2.~~64~~ *75*
Filters/strainers	Pressure Boundary/Fission Product Retention	3.3.2.~~64~~ *75*
Pipes & Fittings	Pressure Boundary/Fission Product Retention	3.3.2.~~64~~ *75*
Pressure Vessel	**Pressure Boundary/Fission Product Retention**	**3.3.2.75**[21]
Pump Casings	Pressure Boundary/Fission Product Retention	3.3.2.~~64~~ *75*
Transmitter/Element	*Pressure Boundary/Fission Product Retention*	*3.3.2.01*
Valve Bodies	Pressure Boundary/Fission Product Retention	3.3.2.40 3.3.2.~~64~~ *75*

Red & Italics – Review based changes
Blue & Bold– RAI/POI based changes (NONE)

[21] **RAI 2.3.3.20-1 and POI-03(c)**

TABLE 2.3.4.1-1 FEEDWATER Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Bolting	Pressure Boundary	~~*3.4.1.05*~~ 3.4.1.08 3.4.1.13 3.4.2.08
Pipes & Fittings	Pressure Boundary	3.4.1.01 3.4.1.02 3.4.1.05 3.4.1.06 3.4.1.13 3.4.2.08 3.4.2.10 3.4.2.11
Valve Bodies	Pressure Boundary	3.4.1.02 3.4.1.05 3.4.1.06 3.4.1.13 3.4.2.08 3.4.2.10 3.4.2.11

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.3.4.2-1 AUXILIARY FEEDWATER Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Bolting	Pressure Boundary	3.4.1.08 3.4.1.13
Filters/strainers	Filtration	3.4.1.05 3.4.2.05 3.4.2.06 3.4.2.09 3.4.2.08 3.4.3.01 3.4.3.02
Flow Element/Orifice Housing	Pressure Boundary	3.4.2.08 3.4.2.09 3.4.3.02
Heat Exchanger	Pressure Boundary	3.4.2.03 3.4.2.04 3.4.2.05 3.4.2.06
Indicator/recorder (housing and sightglass)	Heat Transfer	3.4.2.05 3.4.2.06 3.4.2.07
Pipes & Fittings	Pressure Boundary	3.4.1.02 3.4.1.05 3.4.1.13 3.4.2.05 3.4.2.06 3.4.2.08 3.4.2.09 3.4.3.02
Pump Casings	Pressure Boundary	3.4.1.02 3.4.1.05 ~~*3.4.1.13*~~ 3.4.2.01 3.4.2.02 3.4.2.08 3.4.2.09 3.4.3.01
Tanks	Pressure Boundary	3.4.1.02 3.4.1.05
Transmitter/Element	*Pressure Boundary*	*3.4.1.02* *3.4.2.09*
Turbine Casing	Pressure Boundary	3.4.1.05 ~~*3.4.1.13*~~ 3.4.3.03
Valve Bodies	Pressure Boundary	3.4.1.02

TABLE 2.3.4.2-1 AUXILIARY FEEDWATER Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
		3.4.1.05 3.4.1.13 3.4.2.03 *3.4.2.04* 3.4.2.05 3.4.2.08 3.4.2.09

Red & Italics – Review based changes
Blue – RAI based changes (NONE)

TABLE 2.3.4.3-1
MAIN STEAM AND TURBINE STEAM EXTRACTION
Component Types Subject to Aging Management
Review and Intended Functions

Component Type	Intended Functions	AMR Results
Bolting	Pressure Boundary	3.4.1.08 3.4.1.13 3.4.2.08
Filters/strainers	Filtration Pressure Boundary	3.4.1.01 3.4.1.05 3.4.1.13 3.4.3.0~~2~~ *3* 3.4.3.04
Pipes & Fittings	Pressure Boundary **Flow Restriction**[22]	3.4.1.01 3.4.1.05 3.4.1.06 3.4.1.07 3.4.1.13 3.4.3.03 3.4.3.04 3.4.2.08 3.4.2.10 3.4.2.11
Valve Bodies	Pressure Boundary	3.4.1.01 3.4.1.05 3.4.1.06 3.4.1.07 3.4.1.13 3.4.3.03 3.4.3.04 3.4.2.08 3.4.2.10 3.4.2.11

Red & Italics – Review based changes
Blue & Bold – RAI based changes

[22] **RAI # 2.3.1.2-3**

TABLE 2.4.1-1 CONTAINMENT Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Calcium Silicate Board in Ambient Air	Rated fire barrier	3.3.2.80
Containment Carbon Steel Threaded Fasteners in Ambient Air	Flood protection barrier Pipe whip restraint HELB shielding Structural support to Non-CQE Structural support to CQE	3.5.1.25 3.5.1.27
Containment Concrete Above Grade	Flood protection barrier Rated fire barrier Shelter/protection to CQE Structural support to CQE Missile Barrier	3.5.1.07 3.5.1.08 3.5.1.10 3.5.1.15
Containment Concrete Below Grade	Flood protection barrier Shelter/protection to CQE Structural support to CQE Missile Barrier	3.5.1.07 3.5.1.08 3.5.1.09 3.5.1.15
Interior Containment Concrete in Ambient Air	Flood protection barrier Rated fire barrier Shelter/protection to CQE Structural support to CQE Spray shield or curbs Missile Barrier HELB shielding Pipe whip restraint Shield against radiation	3.5.1.07 *3.5.1.08* 3.5.1.10 3.5.1.15 ~~*3.5.1.16*~~ ~~**3.5.1.23**~~[23]
Containment Equipment Access Hatch and Personnel Air Lock	Pressure boundary/fission product retention	3.5.1.04 3.5.1.05
Containment Equipment Access Hatch Gasket	Pressure boundary/fission product retention	3.5.1.06
Containment Grout in Ambient Air	Structural support to CQE	3.5.1.07 *3.5.1.08* 3.5.1.10 3.5.1.15 3.5.1.16 ~~*3.5 1.23*~~
Containment Ungrouted Masonry Block Walls in Ambient Air	Radiation Shielding	3.5.3.04

[23] **RAI 3.5.1-2**

TABLE 2.4.1-1
CONTAINMENT
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
Containment Mechanical and Electrical Penetrations	Pressure boundary/fission product retention	*3.5.1.02* 3.5.1.03
Containment Mechanical Penetrations With Bellows	Pressure boundary/fission product retention	~~*3.5.1.01*~~ 3.5.1.02
Containment Prestressing/post-tensioning Tendons	Shelter/protection to CQE Structural support to CQE Missile Barrier	~~*3.5.1.11*~~ 3.5.1.14
Containment Stainless Steel Threaded Fasteners	Pressure boundary/fission product retention	3.5.2.25
Containment Steel Liner	Pressure boundary/fission product retention	3.5.1.12
Containment Structural Steel in Ambient Air	Rated fire barrier Pipe whip restraint HELB shielding Structural support to Non-CQE Structural support to CQE	3.5.1.16 3.5.2.30
Fuel Transfer Penetration	Pressure boundary/fission product retention	*3.5.1.02* 3.5.3.03 3.5.2.28
Reactor Cavity Seal Ring	Pressure boundary/fission product retention	3.5.3.03
Reactor Vessel Missile Shields	Missile Barrier	*3.5.1.10* 3.5.1.16 ~~*3.5.1.23*~~
Refueling Cavity Liner	Pressure boundary/fission product retention	3.5.3.03
Trisodium Phosphate Baskets	Structural support to CQE Shelter/protection to CQE	*3.5.1.25* *3.5.1.27* 3.5.2.26

Red & Italics – Review based changes
Blue & Bold – RAI based changes

TABLE 2.4.2.1-1
AUXILIARY BUILDING
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
Auxiliary Building Carbon Steel Expansion/grouted Anchors	Structural support to Non-CQE Pipe whip restraint HELB shielding Structural support to CQE	3.5.1.25 3.5.1.28
Auxiliary Building Carbon Steel Threaded Fasteners	Flood protection barrier Structural support to Non-CQE Pipe whip restraint HELB shielding Structural support to CQE Shelter/protection to CQE	3.5.1.25
Auxiliary Building Concrete Below Grade	Flood protection barrier Shelter/protection to CQE Structural support to CQE	3.5.1.16 3.5.1.17 3.5.1.21 3.5.1.22
Auxiliary Building Exterior Concrete in Ambient Air	Flood protection barrier Rated fire barrier Shelter/protection to CQE Structural support to CQE Missile Barrier	3.5.1.16 3.5.1.21
Auxiliary Building Interior Concrete in Ambient Air	Rated fire barrier Structural support to CQE HELB shielding Shelter/protection to CQE Flood protection barrier Shelter/protection to CQE Shield against radiation	3.5.1.16 3.5.1.21 ~~*3.5.1.23*~~
Auxiliary Building Fire Penetration Barriers	Rated fire barrier	3.3.1.19 3.3.1.25 3.5.2.15 3.5.2.27 3.3.2.51 3.3.2.52 3.3.2.53 3.3.2.54 3.3.2.79
Auxiliary Building Flood Panel Seals	Flood protection barrier	3.5.2.18 3.5.2.19
Auxiliary Building Grout in Ambient Air	Structural support to CQE Pipe whip restraint	3.5.1.25 *3.5.1.16*
Auxiliary Building Masonry in Ambient Air	Structural support to Non-CQE Rated fire barrier	3.5.1.20

TABLE 2.4.2.1-1
AUXILIARY BUILDING
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
Auxiliary Building Pressure Relief Panels	Shelter/protection to CQE	3.5.2.22 3.5.2.23
Auxiliary Building Pyrocrete®	Rated fire barrier	3.3.2.59 3.3.2.60 3.3.2.61
Auxiliary Building Removable Slab Lifting Devices	Structural support to Non-CQE	3.5.2.01
Auxiliary Building Structural Steel	Flood protection barrier HELB shielding Structural support to Non-CQE Pipe whip restraint Structural support to CQE Shelter/protection to CQE	3.5.1.16 *3.5.2.07*
Diesel Fuel Oil Tank Foundation	Structural support to CQE	3.5.1.16 3.5.1.17 3.5.1.21 3.5.1.22
Diesel Generator Missile Shield Enclosure Concrete Below Grade	Structural support to CQE	3.5.1.16 3.5.1.17 3.5.1.21 3.5.1.22
Diesel Generator Missile Shield Enclosure Concrete in Ambient Air	Structural support to CQE Shelter/protection to CQE	3.5.1.16 3.5.1.21 ~~*3.5.1.23*~~
Safety Injection and Refueling Water Tank	Pressure boundary	3.3.2.36
Spent Fuel Pool Liner	Pressure boundary	3.5.1.19
Stainless Steel Pipe Penetrations – Safety Injection and Refueling Water Tank	Pressure boundary	*3.2.1.10*

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.4.2.3-1 INTAKE STRUCTURE Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Bronze Gland and Gland Bolting	Flood protection barrier	3.5.3.01 3.5.2.02
Carbon Steel Expansion/grouted Anchors	Structural support to CQE	3.5.1.25
Carbon Steel Pipe and Pipe Casing	Flood protection barrier	3.3.1.05
Carbon Steel Pipe Sleeve and Flange Floor Penetration	Flood protection barrier	3.5.1.16 3.5.2.08
Carbon Steel Threaded Fasteners Inside Building	Flood protection barrier Structural support to Non-CQE	3.5.1.16
Cast Iron Stuffing Box Floor Penetration	Flood protection barrier	3.5.2.09 *3.5.3.01*
Concrete Below Grade	Flood protection barrier Shelter/protection to CQE Provide source of cooling water for plant shutdown Structural support to CQE	3.5.1.16 3.5.1.17 3.5.1.21 3.5.1.22
Concrete Exposed To Raw Water	Flood protection barrier Provide source of cooling water for plant shutdown Structural support to CQE	3.5.1.16 ~~3.5.2.32~~[24]
Concrete Exterior In Ambient Air	Flood protection barrier Rated fire barrier	3.5.1.16 3.5.1.21
Concrete Interior	Flood protection barrier Rated fire barrier Missile barrier Shelter/protection to CQE	3.5.1.16 3.5.1.21
Rubber components in flood barriers	Flood protection barrier	3.5.2.13 3.5.2.14
Fire Protection Pyrocrete®	Rated fire barrier	3.3.2.59 3.3.2.60 3.3.2.61
Flood Panel Seals	Flood protection barrier	3.5.2.18 3.5.2.19
Grout Protected From Weather	Structural support to CQE	3.5.1.25

[24] RAI 3.5.1-17

TABLE 2.4.2.3-1 INTAKE STRUCTURE Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Sand and Gravel Surrounding The Diesel Fire Pump Fuel Oil Storage Tank	Rated fire barrier	3.5.2.16
Stainless Steel Strainer Backwash Piping Floor Penetration	Flood protection barrier	**~~3.3.1.16~~ 3.5.2.25**[25]
Intake Structure stainless steel raw water pump gland bolting	Flood protection barrier	3.5.2.24
Stainless Steel Threaded Fasteners	Flood protection barrier	3.5.2.25
Structural Steel in Ambient Air	Flood protection barrier Shelter/protection	3.5.1.16

Red & Italics – Review based changes
Blue and Bold– RAI based changes

[25] RAI 3.5-2

TABLE 2.4.2.5-1
FUEL HANDLING EQUIPMENT AND HEAVY LOAD CRANES
Component Types Subject to Aging Management Review and Intended Functions

Component Type	Intended Functions	AMR Results
Concrete Slab Removal Cranes	Structural support to Non-CQE	3.3.1.15
Containment Crane	Structural support to Non-CQE	3.3.1.15
Containment Equipment Hatch Crane and Jib	Structural support to Non-CQE	3.3.1.15
Deborating Demineralizing Area Crane	Structural support to Non-CQE	3.3.1.15
Fuel Transfer Conveyor	Structural support to Non-CQE	3.3.3.02 3.3.2.81
Fuel Transfer Carrier Box	Structural support to Non-CQE	3.3.3.02 3.3.2.81
Fuel Transfer Tube	Structural support to Non-CQE	3.3.3.02 3.3.2.81
New and Spent Fuel Handling Tools	Structural support to Non-CQE	3.3.2.07 3.3.2.08 3.3.2.81 3.3.3.02
New Fuel Storage Rack	Structural support to Non-CQE	3.3.1.10 3.3.2.01 3.3.2.09 3.3.2.75
Refueling Area Crane	Structural support to Non-CQE	3.3.1.15
Refueling Machine	Structural support to Non-CQE	3.3.1.15
Spent Fuel Bridge	Structural support to Non-CQE	3.3.1.15
Spent Fuel Storage Racks	Structural support to CQE Reactivity control	3.3.1.09 3.3.1.11 3.3.2.81
Tilting Machines	Structural support to Non-CQE	3.3.3.02 3.3.2.81
Upper Guide Lift Rig	Structural support to CQE	3.3.3.02 3.3.2.81
Waste Evaporator Equipment Handling Crane	Structural support to Non-CQE	3.3.1.15
Reactor Vessel Closure Head Lift Rig	Structural support to CQE	3.3.1.15
Crane Expansion Anchors	*Structural support to Non-CQE*	*3.5.1.25*

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.4.2.6-1 COMPONENT SUPPORTS Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Component Support Carbon Structural Steel in Ambient Air	Structural support to CQE Structural support to Non-CQE	3.5.1.25 3.5.1.27 3.5.1.28
Component Support Carbon Steel Threaded Fasteners in Ambient Air	Structural support to CQE Structural support to Non-CQE	3.5.1.25 3.5.1.27 3.5.1.28
Component Support Epoxy Grout in Ambient Air	Structural support to CQE	3.5.1.25
Component Support Grout in Ambient Air	Structural support to CQE Structural support to Non-CQE	3.5.1.25
Component Support High Strength Steel Threaded Fasteners in Ambient Air	Structural support to CQE Structural support to Non-CQE	3.5.1.25 3.5.1.27 ~~3.5.2.29~~ *3.5.1.28*
Component Support Lubrite Plate in Ambient Air	Structural support to CQE	3.5.1.28
Component Support Stainless Structural Steel in Ambient Air	Structural support to CQE Structural support to Non-CQE	3.5.2.25 3.5.2.26
Component Support Stainless Structural Steel in Borated Treated Water	Structural support to CQE Structural support to Non-CQE	3.5.2.28 3.5.3.03 3.5.2.31
Component Support Stainless Steel Threaded Fasteners in Ambient Air	Structural support to CQE Structural support to Non-CQE	3.5.2.32
Component Support Carbon Steel Spring Support Anchorage	Structural support to CQE	3.5.3.02
Component Support Weathering Carbon Steel in Ambient Air	Structural support to CQE	3.5.1.27 3.5.1.28

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.4.2.7-1 DUCT BANKS Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Exterior Concrete In Ambient Air	Shelter/protection to CQE Missile barrier	3.5.1.16 3.5.1.21
Concrete Below Grade	Structural support Shelter/protection to CQE Missile barrier	3.5.1.16 3.5.1.17 3.5.1.21
Interior Concrete	Structural support Shelter/protection to CQE Missile barrier	3.5.1.16 3.5.1.21
Manhole MH-31 Cover	Shelter/protection to CQE Missile barrier	3.5.2.17
Manhole MH-31 Flange	Structural support Missile barrier	3.5.2.07
Manhole MH-31 Foam Blocks	Flood protection barrier	3.5.2.20 3.5.2.21
Manhole MH-5 Cover and Flange	Shelter/protection to CQE Structural support *to Non-CQE* Missile barrier	3.5.2.17

Red & Italics – Review based changes
Blue & Bold – RAI based changes (NONE)

TABLE 2.5.2-1 CONTAINMENT ELECTRICAL PENETRATIONS Component Types Subject to Aging Management Review and Intended Functions		
Component Type	**Intended Functions**	**AMR Results**
Electrical Penetrations	Electrical Continuity Pressure Boundary	3.6.1.01 3.6.1.02 3.6.1.05 3.5.1.03
Instrumentation Cable Pigtails	**Electrical Continuity**	**3.6.1.03**[26]

Red & Italics – Review based changes (NONE)
Blue & Bold – RAI/POI based changes

[26] POI-12