3 Aging Management Review Results

3.0 Common Aging Management Programs

3.0.1 Introduction

This section of the SER contains the staff's evaluation of 18 AMPs that are in Appendix B of the LRA, and are referenced as a part of the AMR for two or more of the systems and/or structures. It should be noted that the staff's conclusions on the evaluations of these 18 common AMPs may be predicated on the assumption that they are implemented in conjunction with other AMPs (if more than one AMP is credited by the applicant) as discussed in subsequent sections of this SER for managing the effects of aging of SCs that are subject to an AMR.

3.0.2 Program and Activity Attributes

The staff's evaluation of the applicant's AMPs focuses on program elements, rather than the details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the current licensing basis (CLB) for the period of extended operation, the staff used 10 elements to evaluate each program and activity. The 10 elements of an effective AMP were developed as part of NUREG 1800, "Standard Review Plan for License Renewal," which was issued in July 2001. This SER describes the extent to which the ten elements are applicable to a particular program or activity, and evaluates each program and activity against those elements that are determined to be applicable. On the basis of NRC experience with maintenance programs and activities, the staff concluded that conformance with the 10 elements of an AMP, or a combination of AMPs, provides reasonable assurance that an AMP (or combination of programs and activities) is demonstrably effective at managing an applicable aging effect. The following 10 elements of an effective AMP will be considered in evaluating each AMP used by the applicant to manage the applicable aging effects identified within this SER:

1. scope of program
2. preventive actions
3. parameters monitored or inspected
4. detection of aging effects
5. monitoring and trending
6. acceptance criteria
7. corrective actions
8. confirmation process
9. administrative controls
10. operating experience

In the LRA, Appendix B, Section B.2.2, "Attribute Definitions," the applicant described the elements involving corrective actions and confirmation processes for license renewal. The staff notes that Selected Licensee Commitments (SLCs) are part of the UFSARs for McGuire and Catawba and, therefore, are controlled documents that delineate regulatory requirements. The staff's evaluation of the applicant's corrective action program was evaluated generically and is discussed separately in Section 3.0.4 of this SER.

3.0.3 Common Aging Management Programs and Activities

3.0.3.1 Borated Water System Stainless Steel Inspection

The applicant described its Borated Water System Stainless Steel Inspection program in Section B.3.4 of the LRA. This program is credited with managing the potential aging effects of loss of material and cracking due to exposure to alternate wetting and drying in borated water environments. The staff reviewed Section B.3.4 of the LRA to determine whether the applicant has demonstrated that borated water system stainless steel inspection activities will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.1.1 Technical Information in the Application

Section B.3.4 of the LRA describes the Borated Water Systems Stainless Steel Inspection as a way of characterizing any loss of material or cracking of stainless steel components exposed to alternate wetting and drying in borated water environments. The purpose of the program is to determine if alternate wetting and drying of components in the containment spray and refueling water systems is causing aging in stainless steel components such that they may lose their pressure boundary function. It is described as a one time-inspection of stainless steel components, welds, and heat affected zones, as applicable, in the containment spray system in the area of the internal air/water interface. The location to be inspected is stagnant and isolated from the rest of the containment spray system; therefore, it is not controlled by the Chemistry Control Program. As the water evaporates, contaminants could concentrate and lead to loss of material or cracking.

3.0.3.1.2 Staff Evaluation

The staff's evaluation of the Borated Water System Stainless Steel Inspection activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] The applicant defined the scope of the Borated Water Systems Stainless Steel Inspection program as including the stainless steel components exposed to an alternate wetting and drying borated water environment in the following McGuire and Catawba systems:

- Containment spray
- Refueling water

The staff finds the scope of the program to be acceptable and appropriate to determine if alternate wetting and drying of components will result in aging effects. [Preventive or Mitigative Actions] There are no preventative actions taken as part of this program, and the staff did not identify the need for any preventative actions.

[Parameters Monitored or Inspected] The applicant stated that the parameter inspected by the Borated Water Systems Stainless Steel Inspection program is pipe wall thickness, as a measure of loss of material or cracking of stainless steel components, at one of twelve possible locations at each site. The staff noted that stainless steel has demonstrated susceptibility to intergranular stress corrosion cracking in low-temperature borated water systems in pressurized water reactors, particularly in stagnant lines, at weld heat-affected zones (HAZ), involving weld procedures that resulted in sensitization of the stainless steel in the HAZ. The staff noted that not all welds, stress patterns, impurity levels, and species of steel are necessarily similar.

By letter dated January 28, 2002, the staff requested, in RAI B.3.4-1, the applicant to justify why inspection of only one of twelve locations adequately represents the durability of material at the other eleven locations and to explain the process for inspection population expansion should aging effects be identified. In its response dated March 15, 2002, the applicant responded that a search of operating experience did not reveal any instances of failure of stainless steel components exposed to an alternate wetting and drying in a borated water environment, so there is uncertainty as to whether degradation will occur. The applicant intends to evaluate all possible locations and select the one that would most likely result in the identification of loss of material or cracking if they were occurring. Criteria such as geometry, proximity to hot equipment, and operating experience will be used to select the locations for inspection. Any inspection population expansion would be driven by the corrective action process if either loss of material or cracking is found.

By letter dated January 28, 2002, the staff also requested, in RAI B.3.4-2, the applicant to describe the criteria for (1) assessing the severity of any observed degradation, and (2) determining whether or not corrective action is necessary. In its response dated March 15, 2002, the applicant stated that the criteria would be developed at the time of the inspection. Criteria such as the ASME Code, results from additional inspections, and operating experience may be used to assess the severity of the degradation and the need for corrective action. In RAI B.3.4-3, the staff asked if the inspections will be looking for evidence of pitting, and if so, asked the applicant to discuss the inspection techniques that will be used to reliably identify the presence of pits. In its response dated March 15, 2002, the applicant stated that the volumetric methods to be used in the inspections will detect loss of material, including evidence of pitting. The presence of a few pits would not be a structural concern that could lead to loss of component function and heavy pitting would be revealed as general wall loss by volumetric examination techniques.

The staff finds the information provided in the LRA and the applicant’s responses to these RAIs reasonable and acceptable because the applicant proposes to adequately monitor the conditions that relate to the aging effects of concern.

[Detection of Aging Effects] The applicant indicated that this AMP is a one-time inspection that will detect the presence and extent of loss of material or cracking of stainless steel components. In RAI B.3.4-1, the staff requested the applicant to justify why a one-time inspection was adequate, given the susceptibility of stainless steel to intergranular stress corrosion cracking in certain environments. In its response, the applicant stated that engineering judgment would be applied to determine if corrective actions, including an increase in the inspection population, are warranted based on the result of the inspection.

Based on the staff's review of the LRA, the applicant's responses to the staff's RAIs, and the applicant's commitments to perform this one-time inspection and make modifications as needed based on industry operating experience or other evaluations, the staff finds that the monitoring is appropriate for the scope or this inspection. The staff concurs that trending is not required. Based on information provided in the LRA and the responses to the RAIs described above, the staff concludes that this one-time inspection is capable of detecting the presence and extent of loss of material or cracking of stainless steel components within the scope of the program prior to loss of component function.

[Monitoring and Trending] As described in Section B.3.4 of the LRA, the Borated Water Systems Stainless Steel Inspection program will inspect stainless steel components, welds, and heat affected zones, as applicable, in the containment spray system in the area of the internal air/water interface. The applicant identified the containment spray system as the most susceptible to degradation from this environment. The borated water environment found downstream of selected valves in the containment spray system is stagnant and isolated from the remainder of the system, and therefore, not controlled by the chemistry control program. During valve testing, water from the refueling water storage tank is introduced in the pipe, with level in the piping reaching the same elevation as the tank. Since the pipe is open to containment, evaporation occurs and concentration of contaminants could occur at the air/water interface. This concentration of contaminants could lead to loss of material or cracking.

The applicant will inspect one of twelve possible locations at each site using volumetric technique. If no parameters are known that would distinguish the susceptible locations at each site, one of the twelve available at each site will be examined based on accessibility and radiological concerns. The applicant will apply the results of this inspection to the specific stainless steel components exposed to an alternate wetting and drying borated water environment in the refueling water system. No actions are taken as part of this activity to trend inspection results. Should industry data or other evaluations indicate that the above inspections can be modified or eliminated, the Applicant will provide plant-specific justification to demonstrate the basis for the modification or elimination.

Based on the staff's review of the LRA, the applicant's responses to RAIs 3.4-1 and 3.4-2, and the applicant's commitments to perform this one-time inspection and make modifications as needed based on industry operating experience or other evaluations, the staff finds that the monitoring is appropriate for the scope or this inspection. The staff concurs that trending is not required.

[Acceptance Criteria] The applicant described the acceptance criteria for the Borated Water Systems Stainless Steel Inspection as no unacceptable loss of material or cracking that could result in a loss of the component intended function, as determined by engineering evaluation. By letter dated January 28, 2002, the staff requested, in RAI B.3.4-2, the applicant to provide its criteria for assessing the severity of the observed degradation and for determining whether or not corrective action is necessary. In its response dated March 15, 2002, the applicant stated that the criteria would be developed at the time of the inspection. Criteria such as the ASME Code, results from additional inspections, and operating experience may be used to assess the severity of the degradation and the need for corrective action. Because the inspection techniques are capable of detecting degradation of concern, the staff finds the applicant's response reasonable and acceptable.

[Operating Experience] The LRA describes this as a one-time inspection for which there is no operating experience. However, volumetric examination techniques have been effective in detecting loss of material or cracking in stainless steel components. The staff finds this reasonable and acceptable.

3.0.3.1.3 FSAR Supplement

In Appendix A-1, Section 18.2.2, and Appendix A-2, Section 18.2.2, of the LRA, the applicant provided proposed new UFSAR sections for McGuire and Catawba, respectively. The staff reviewed this material and found it to be consistent with the material provided in LRA and, therefore, acceptable.

3.0.3.1.4 Conclusion

The staff has reviewed the information provided in Section B.3.4 of the LRA, the summary description of the Borated Water Systems Stainless Steel Inspection program in Appendix A of the LRA, and the applicant's March 15, 2002, response to the staff's RAIs. On the basis of the above evaluation, the staff finds that the Borated Water Systems Stainless Steel Inspection program will adequately manage the aging effects such that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.2 Chemistry Control Program

The applicant described its chemistry control program in Section 3.6 of Appendix B of the LRA. The staff reviewed the application to determine whether the applicant has demonstrated that the chemistry control program will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.2.1 Technical Information in the Application

The chemistry control program applies to the systems containing four different chemical environments: borated water, closed cooling water, treated water and fuel oil. The major systems containing these environments are listed in the table below. The table also contains the industry guidelines and standards used to develop the corresponding aging management procedures.

Chemical Environment	Major Systems	Industry Guidelines, Codes, or Standards
Borated Water	Reactor Coolant Refueling Water Spent Fuel Pool Cooling	EPRI Report TR-105714-R4 “PER Primary Water Chemistry Guidelines”
Closed Cooling Water	Closed Cooling Water System	EPRI Report TR-107396 “Closed Cooling Water Chemistry Guidelines”
Treated Water	Demineralized Water Feedwater SG Wet Lay-up Recirculation	EPRI Report TR-102134-R5 “PER Secondary Water Chemistry Guidelines”
Fuel Oil	Diesel Generator Fuel Oil Standby Shutdown Diesel	ASTM Standards

This program manages the relevant conditions that lead to the onset and propagation of loss of material and cracking which could lead to a loss of structure or component intended functions. Relevant conditions are specific parameters such as halogens, dissolved oxygen, conductivity, biological activity, and corrosion inhibitor concentrations that could lead to loss of material and/or cracking if not properly controlled. The applicant concluded that the chemistry control program will manage loss of material and/or cracking of components exposed to borated water, closed cooling water, fuel oil and treated water environments.

3.0.3.2.2 Staff Evaluation

The staff’s evaluation of the chemistry control program focused on how the program managed aging effects through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program. The staff’s evaluation of the corrective actions, confirmation process, and administrative controls is documented in Section 3.0.4 of this SER.

After completing its initial review, the staff identified several areas where additional information was needed. The LRA did not classify fouling of the heat exchangers in several systems as an aging effect. The applicant did not specify how the procedures in the site program manuals and the parameters monitored for each of the three chemistries deviated from the EPRI chemistry guidelines. The applicant also did not specify the acceptance criteria for fuel oil. By letter dated January 28, 2002, the staff issued RAIs B.3.6-1, B.3.6-2, B.3.6-3 and B.3.6-4 to obtain clarification from the applicant. By a letter dated March 15, 2002, the applicant responded to the staff’s RAIs. It modified the plant’s UFSAR by including fouling to the mechanisms which could lead to a loss of structure or component intended function. The applicant indicated that the deviations from the EPRI guidelines were included in the plant procedures with proper technical documentation to justify them. The applicant also referenced the appropriate sections of the TS bases for Catawba and McGuire containing the descriptions of the standards used in developing the acceptance criteria for fuel oil.

This program manages specific parameters such as halogens, dissolved oxygen, conductivity, biological activity, and corrosion inhibitor concentrations that lead to the onset and propagation of loss of material and cracking if not properly controlled. The chemistry control program manages the aging effects caused by loss of material, cracking and fouling in the components exposed to the four different chemical environments specified in the table above. Except for the program scope, the other evaluations of the chemistry control program apply to both Catawba and McGuire.

The staff's evaluation of the applicant's quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] The scope of the program consists of managing aging effects of the components located in the systems containing four chemical environments: borated water, closed cooling water, treated water and fuel oil. Monitoring and controlling these environments will ensure that aging effects for the affected components will be properly managed.

For the borated water environment, the chemistry control program manages aging effects of the components in the following systems:

In Catawba and McGuire:

- boron recycle
- chemical and volume control
- containment spray
- equipment decontamination
- nuclear sampling
- residual heat removal

In Catawba only:

- safety injection

For the closed cooling water environment, the chemistry control program manages aging effects of the components in the following systems:

In Catawba and McGuire:

- auxiliary building ventilation
- building heating or heating water
- component cooling
- control area chilled water
- diesel generator cooling water
- ice condenser refrigeration
- recirculation cooling water
- standby cooling shutdown diesel

In addition, control of the closed cooling water environment manages aging effects of the heat exchangers in the following systems:

In Catawba and McGuire:

- chemical and volume control
- control area or control room area ventilation
- diesel generator lube oil
- residual heat removal
- waste gas

For the treated water environment, the chemistry control program manages aging effects of the components in the following systems:

In Catawba and McGuire:

- auxiliary feedwater
- auxiliary steam
- feedwater pump turbine exhaust or turbine exhaust
- liquid radwaste or liquid waste recycle
- main steam
- main steam supply to auxiliary equipment
- main steam vent to atmosphere
- nuclear sampling
- steam generator blowdown or steam generator blowdown recycle
- steam generator wet lay-up recirculation

In Catawba only:

- condensate
- condensate storage
- equipment decontamination

In McGuire only:

- liquid waste monitor and disposal
- conventional chemical addition

For the fuel oil environment, the chemistry control program manages aging effects of the components in the following systems:

In Catawba and McGuire:

- diesel generator fuel oil
- standby shutdown diesel

The staff finds the program scope to be acceptable because, for each chemical environment, the applicant specified the systems containing the components whose aging effects could be managed by the application of one of the chemistry control programs specified in the LRA.

[Preventive or Mitigative Actions] The applicant’s program monitors and controls the relevant conditions such as halogens, dissolved oxygen, conductivity, biological activity, and corrosion inhibitor concentrations to manage loss of material and cracking. These corrosive contaminants are either removed, their concentrations minimized, or treatments are added and/or maintained to negate their corrosive tendencies. The objective of the chemistry control program is to ensure that the chemistry parameters for water and diesel fuel oil remain within the values specified by the plant’s TS based on the EPRI chemistry guidelines, the plant

UFSARs, and vendor recommendations for water and fuel oil quality. Although this activity will not completely eliminate damaging effects of the chemical environments to which the components are exposed, the program will reduce their severity and will ensure that resultant aging effects will not invalidate the functions performed by the affected components. The staff finds that these procedures are adequate because they include all of the activities needed to mitigate age-related effects that are within the scope of license renewal.

[Parameters Inspected or Monitored] The chemistry control program monitors the parameters specified in the plant's TS, based to large extent, on the EPRI guidelines. The staff finds that, by monitoring these parameters, the applicant will obtain the information needed for evaluation of the operational conditions in the system exposed to the water and fuel oil environments.

[Detection of Aging Effects] The chemistry monitoring programs are preventive programs and as such are not credited for detecting aging effects. The staff finds this acceptable.

[Monitoring and Trending] The chemistry control program measures the relevant parameters within specified frequencies. From these measurements, performed over a time period, trends in water and fuel oil chemistry characteristics can be established. This will permit the applicant to make appropriate adjustments to the chemistry in the systems included in the scope of the LRA. The staff finds that this approach will ensure effectiveness of the chemistry control program.

[Acceptance Criteria] The acceptance criteria for the chemistry parameters to be monitored in the systems carrying borated water, closed cooling water, treated water and diesel fuel oil are determined by TS requirements, EPRI guidelines, UFSAR, and vendor recommendations for water and fuel oil quality. They are specific for different chemistry environments. The staff finds these criteria acceptable because the limits imposed by them ensure that the aging effects for all the components within the scope of the LRA will be properly managed.

[Operating Experience] The current operating experience for the systems covered by the chemistry control program has demonstrated the effectiveness of the program. Aging effects in all the components exposed to the borated and treated water and to the fuel oil were successfully managed. The components in the component cooling systems exposed to closed cooling water exhibited instances of cracking at welds due to nitrite induced stress corrosion of carbon steel. However, this source of corrosion was eliminated by a suitable modification of the chemistry control program. The staff finds that by following the procedures specified in the current chemistry control program, the applicant will ensure that the aging effects will be properly managed.

3.0.3.2.3 FSAR Supplement

The applicant provided in Appendix A-1 (McGuire) and A-2 (Catawba) new FSAR sections describing the chemistry control program. The information provided for the FSAR is consistent with the program described in Appendix B; however, the applicant should include a discussion in the FSAR Supplement regarding the specific technical specifications and the EPRI guidelines that are mentioned in Appendix B for the chemistry control program. Pending the staff's receipt of an updated FSAR supplement, this issue is characterized as open item 3.0.3.2.3-1.

3.0.3.2.4 Conclusion

The staff has reviewed the chemistry control program in Section 3.6, of Appendix B of the LRA and the applicant's responses to the staff's RAIs. On the basis of this review and the above evaluation, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the chemistry control program will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.3 Containment In service Inspection Plan - IWE

The applicant described its containment In service inspection (IS) activities in Section B.3.7 of the LRA. This activity is credited with managing the potential aging of containment structures within the scope of license renewal. The staff reviewed Section B.3.7 of the LRA to determine whether the applicant has demonstrated that the containment IS activities will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.3.1 Technical Information in the Application

Section B.3.7 of the LRA describes the Containment Inservice Inspection (ISI) Plan - IWE. The purpose of this plan is to manage the aging effect of loss of material for the ASME Code Class MC pressure retaining steel components and their integral attachments for the period of extended operation. Section B.3.7 of the LRA summarizes the plan as follows:

> The "Containment Inservice Inspection Plan - IWE" was developed to implement applicable requirements of 10 CFR 50.55a. Section 50.55a(g)(4) requires that throughout the service life of nuclear power plants, components which are classified as either Class MC or Class CC pressure retaining components and their integral attachments must meet the requirements, except design and access provisions and pre-service examination requirements, set forth in Section XI of the ASME Code and Addenda that are incorporated by reference in §50.55a(b). Furthermore, §50.55a(g)(4)(v)(A) requires that metal containment pressure retaining components and their integral attachments must meet the In service inspection, repair, and replacement requirements applicable to components which are classified as ASME Code Class MC. These requirements are subject to the limitation listed in paragraph (b)(2)(vi) and the modifications listed in paragraphs (b)(2)(viii) and (b)(2)(ix) of §50.55a, to the extent practical within the limitations of design, geometry and materials of construction of the components [Reference B - 20]. The "Containment Inservice Inspection Plan - IWE" is a condition monitoring program.

The components within the scope of Subsection IWE at McGuire and Catawba are metal containment pressure retaining components and their integral attachments, metal containment pressure retaining bolting, and metal containment surface areas, including welds and base metal.

The applicant concluded that the continued implementation of Containment ISI Plan - IWE provides reasonable assurance that the containment steel components will be managed such that the component intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation.

3.0.3.3.2 Staff Evaluation

The staff's evaluation of the Containment ISI Plan - IWE focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the administrative controls are implemented through administrative procedures. The staff's evaluation of the administrative controls is provided in Section 3.0.4 of this SER. The remaining elements are discussed below.

[Program Scope] Section B.3.7 of the LRA provides the following information related to the scope of the inspection activities:

> The scope of the "Containment Inservice Inspection Plan - IWE" includes examination of items specified in Subsection IWE-1000, except for items that are non-mandatory as documented in 10 CFR 50.55a(b)(2)(ix)(C) and for items whose examinations have been eliminated as a result of approved alternatives submitted in accordance with 10 CFR 50.55a(a)(3). The components within the scope of Subsection IWE at McGuire and Catawba are metal containment pressure retaining components and their integral attachments; metal containment pressure retaining bolting; and metal containment surface areas, including welds and base metal. Subsection IWE exempts from examination (1) components that are outside the boundaries of the containment as defined in the plant-specific design specification; (2) embedded or inaccessible portions of containment components that met the requirements of the original construction code of record; (3) components that become embedded or inaccessible as a result of vessel repair or replacement, provided IWE-1232 and IWE-5220 are met; and (4) piping, pumps, and valves that are part of the containment system, or which penetrate or are attached to the containment vessel.
> 10 CFR 50.55a(b)(2)(ix) specifies additional requirements for inaccessible areas. It states that the licensee shall evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas.

The scope of this program is in accordance with the IS requirements of 10 CFR 50.55a, and is therefore acceptable to the staff.

[Preventive Action] There are no preventative actions taken as part of this program, Since this is a condition monitoring program, the applicant prefers not to take credit for certain preventive measures such as coating. The staff did not identify the need for any additional preventive actions, and finds the applicant's approach acceptable.

[Parameters Monitored or Inspected] Section B.3.7 of the LRA describes the inspections. Coated surfaces are examined for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Uncoated areas are examined for evidence of cracking, discoloration, wear, pitting, corrosion, gouges, surface discontinuities, dents, and other signs of surface irregularities. Moisture barriers are examined for wear, erosion, separation from surfaces, embrittlement/cracking, or other defects that may permit moisture intrusion to inaccessible surfaces of the containment. Bolted connections are examined for defects that could affect leak-tightness or structural integrity. Table IWE-2500-1 specifies seven categories for examination, and references the applicable section in IWE-3500 for the aging effects that are evaluated.

The LRA states that the Containment ISI Plan - IWE does not require monitoring or inspection of the following items in accordance with Table IWE-2500-1:

- Category E-B, Items E3.10, E3.20, and E3.30 (containment penetration welds, flange welds, and nozzle-to-shell welds)
- Category E-D, Items E5.10 and E5.20 (seals and gaskets)
- Category E-F, Item E7.10 (dissimilar metal welds)
- Category E-G, Item E8.20 (bolted connections - bolt torque or tension

By letter dated January 28, 2002, the staff requested, in RAI B.3.7-1, information related to the exclusion of Categories E-B, E-D, E-F, and E-G from the program. In its response dated March 11, 2002, the applicant provided the following:

> <u>Category E-B</u>
> Categories E-B (Pressure Retaining Welds) and E-F (Pressure Retaining Dissimilar Metal Welds) Examinations are excluded from the Inservice Inspection Plan - IWE for McGuire and Catawba. The basis for excluding these examinations is 10 CFR 50.55a(b)(2)(ix)(C) and SECY-96-080, which states that "the NRC concludes that requiring these inspections is not appropriate. There is no evidence of problems associated with welds of this type in operating plants.
>
> <u>Category E-D</u>
> Category E-D, Item 5.10 (Seals) and Item E5.20 (Gaskets) examinations are excluded from the Inservice Inspection Plan - IWE for McGuire and Catawba. The basis for excluding these examinations is documented in Duke Energy Corporation Request for Relief Serial No. 98-GO-001, approved by SER submitted by NRC letter dated September 3, 1998. Alternative examinations to be performed are as follows:
>
>> The leak-tightness of containment pressure retaining seals and gaskets will be verified by leak rate testing in accordance with 10 CFR 50, Appendix J, as required by Technical Specifications
>
> Category E-D, Item E5.30 (Moisture Barriers) are NOT excluded from the Inservice Inspection Plan - IWE for McGuire and Catawba.
>
> <u>Category E-G</u>
> Category E-G, Item E8.20 (Bolt Torque or Tension Tests for Bolted connections) are excluded from the Inservice Inspection Plan - IWE for McGuire and Catawba. The basis for excluding these examinations is documented in Duke Energy Corporation Request for Relief Serial No. 98-GO-002, approved by SER submitted by NRC letter dated November 24, 1998. Alternative examinations to be performed are as follows:
>
> (1) Bolted connections shall receive a visual, VT-1 examination in accordance with requirements of Table IWE-2500-1, Examination Category E-G, Pressure Retaining Bolting, Item No. E8.10, and (2) A local leak rate test shall be performed on all containment penetrations, airlocks, and other pressure retaining bolted connections in accordance with 10 CFR 50, Appendix J.
>
> Category E-G, Item E8.10 (Bolted Connections Visual, VT-1) are <u>NOT</u> excluded from the <u>Inservice Inspection Plan - IWE</u> for McGuire and Catawba.

With regard to Categories E-B and E-F, the staff notes that, for the reasons cited in SECY-96-080 and quoted by the applicant, 10 CFR 50.55a(b)(2)(ix)(C) makes the Category E-B (pressure retaining welds) and Category E-F (pressure retaining dissimilar metal welds) examinations optional. However, if an examination (general or VT-3) indicates loss of material or degradation of these welds, the users of 10CFR50.55a should perform the examinations as required by Subsection IWE. For example, the staff is aware of degradation of containment bellows where the dissimilar metals (stainless steel and carbon steel) are welded. However, this issue is discussed in detail in the staff's evaluation of Sections 3.5, 4.6, and 3.0.3.4 of this SER. Thus, the staff considers this response to be acceptable.

With regard to Category E-D, the staff notes that a review of the cited relief request indicates that the applicant is implementing the approved alternative of ensuring the leak-tightness of containment pressure retaining seals and gaskets by leak rate testing in accordance with 10 CFR 50, Appendix J, as required by TS. With regard to E-G, a review of the cited relief request indicates that the applicant is implementing the approved alternative of performing visual (VT-1) examinations and leak rate tests in accordance with the approved alternative, and that the leak rate testing is in accordance with 10 CFR Part 50, Appendix J, as required by the TS. Since the applicant received relief from this requirement, the staff finds the applicant's response and the program element acceptable.

[Detection of Aging Effects] Section B.3.7 of the LRA states that the extent and frequency of examinations are specified in IWE-2400 and IWE-2500, and that the method of examination for each item is specified in IWE-2500 and Table IWE-2500-1. Augmented inspections are performed as described below. The staff concludes that the inspections will detect loss of material before there is a loss of structure or component intended function(s). The staff finds this acceptable.

[Monitoring and Trending] Section B.3.7 of the LRA states that the frequency and scope of examinations are sufficient to ensure that aging effects would be detected before they would compromise the design basis requirements. The LRA states the following:

> The extent and frequency of examinations are specified in IWE-2400 and IWE-2500. The inspection intervals are not restricted by the Code to the current term of operation and are valid for any period of extended operation. Subsection IWE examinations are performed as prescribed during each ten year interval. The method of examination for each item is specified in IWE-2500 and Table IWE-2500-1.
>
> All surface areas are monitored by virtue of examinations performed in accordance with IWE-2400 and IWE-2500. When component examination results require evaluation of flaws, evaluation of areas of degradation, or repairs, and the component is found to be acceptable for continued service, the areas containing such flaws, degradation, or repairs shall be reexamined during the next inspection period, in accordance with Examination Category E-C (containment surfaces requiring augmented examination). When these reexaminations reveal that the flaws, areas of degradation, or repairs remain essentially unchanged for three consecutive inspection periods, these areas no longer require augmented examination in accordance with Examination Category E-C. IWE-2430 requires that (a) examinations performed during any one inspection that reveal flaws or areas of degradation exceeding the acceptance standards shall be extended to include an additional number of examinations within the same category approximately equal to the initial number of examinations, and (b) when additional flaws or areas of degradation that exceed the acceptance standards are revealed, all of the remaining examinations within the same category must be performed to the extent specified in Table IWE-2500-1 for the inspection interval. Alternatives to these examination requirements are provided in 10 CFR 50.55a(b)(2)(ix)(D), and as documented in approved Requests for Relief, submitted in accordance with 10 CFR 50.55a(a)(3).

The LRA describes a complete procedure for monitoring and trending; however, it does not discuss the specific areas identified for augmented inspection. By letter dated January 28, 2002, the staff requested, in RAI B.3.7-2, a summary of such areas for each of the plants. In its response dated March 11, 2002, the applicant stated that the Inservice Inspection requirements for Steel Containment Vessels at McGuire and Catawba Nuclear Stations currently comply with

10CFR50.55a and the ASME Boiler and Pressure Vessel Code, Section XI, 1992 Edition with the 1992 Addenda, as modified by approved Requests for Relief granted in accordance with 10CFR50.55a(a)(3)(i) and (a)(3)(ii). The applicant also described, in detail, the areas that are designated for augmented inspection for each unit of McGuire and Catawba as follows:

McGuire 1:

1. The following items/areas are examined in accordance with Category E-C, Item E4.11:
    - Moisture barriers at the embedment zone around the periphery of the exterior side of the steel containment vessel
    - Moisture barrier at the interface between the steel containment vessel and the Fuel Transfer Tube Radiation shielding concrete on the exterior side of the steel containment vessel

The above items were selected for augmented examination due to conditions observed on these moisture barriers when examined in accordance with Table IWE-2500-1, Examination Category E-D, Item E5.30.

2. The following items/areas are examined in accordance with Category E-C, Item E4.12:
    - Surface areas directly behind the insulation panel attached to the interior surface of the containment vessel approximately 36" above the embedment zone. These locations were selected for examination because the top of the insulation panel had not been sealed to prevent moisture intrusion, and because evidence of moisture intrusion had been noted during past inspections. Examination area is approximately 12" wide and extends nearly all of the way around the periphery of the containment vessel.
    - Surface areas directly behind cork expansion joint material between the interior concrete structure and steel containment vessel at Elevation 752' + 1 3/8" between azimuths 104° and 122° (approx.). This location was selected for examination because the cork expansion joint material has not been removed at this location, and it is still possible for moisture to accumulate behind the expansion joint material. During past inspections, some staining had been observed beneath this area, indicating that moisture intrusion had occurred.

Ultrasonic thickness measurements on the above surfaces are performed from the exterior of the containment vessel.

McGuire 2:

1. The following items/areas are examined in accordance with Category E-C, Item E4.11:
    - Moisture barriers at the embedment zone around the periphery of the exterior side of the steel containment vessel, between azimuths 0° and 180° (approx.) and between azimuths 270° and 360° (approx.)
    - Moisture barrier at the interface between the steel containment vessel and the Fuel Transfer Tube Radiation shielding concrete on the exterior side of the steel containment vessel

The above items were selected for augmented examination due to conditions observed on these moisture barriers when examined in accordance with Table IWE-2500-1, Examination Category E-D, Item E5.30.

2. The following items/areas are examined in accordance with Category E-C, Item E4.12:
    - Examination areas are identical to those on Unit 1, except that the following additional area is also examined:
    - Surfaces between the steel containment vessel and the Fuel Transfer Tube Radiation Shielding concrete on the interior of the vessel, between elevations 728'+4" and 729'+4". Examination area extends approximately 3 feet on each side of the Fuel Transfer Tube and is examined from the exterior of the containment vessel. This location was selected for examination because general visual examinations conducted in accordance with Table IWE-2500-1, Examination Category E-A, Item E1.11 detected evidence of borated water at this location on the interior surface of the containment vessel.

Ultrasonic thickness measurements on the above surfaces are performed from the exterior of the containment vessel.

Catawba 1:

1. The following items/areas are examined in accordance with Category E-C, Item E4.11:
    - Surface areas on the interior of the containment vessel, located between azimuths 247° and 303° (approx.), below Elevation 593'+10 ½", along the top of the cork expansion joint material installed between the interior concrete structure and the containment vessel at the VX Fan Pit floor. This location was selected for examination because most of the cork expansion joint material has not been removed at this location, moisture intrusion has occurred, and some rusting and minor pitting has been observed on containment shell surfaces along the top of the cork material.

2. The following items/areas are examined in accordance with Category E-C, Item E4.12:
    - Surface areas directly behind the cork expansion joint material installed between the containment vessel and interior concrete structure at the VX Fan Pit floor between azimuths 247° and 303° (approx.), between Elevations 593'+9 3/8" and 596'+9 3/8" (approx.). This location was selected for examination because conditions noted at the VX Fan Pit floor on the interior of the containment vessel were considered to be an indicator of possible degradation of the containment vessel shell plate behind the expansion joint material.
    - Surface areas directly behind cork expansion joint material along the top of floor joints between the interior concrete structure and steel containment vessel at the following locations. These locations were selected for examination because most of the cork insulation panel has not been removed, and evidence of moisture and staining has been observed beneath these areas on the interior side of the vessel:
        - between Elevations 565'+5 5/8" and 564'+5 5/8" (approx.), between azimuths 0° to 250°, and 270° to 360° (approx.)
        - between Elevations 579'+1 3/8" and 578'+1 3/8" (approx.), between azimuths 104° to 122° (approx.)
        - between Elevations 594'+8 3/8" and 593'+8 3/8" (approx.), between azimuths 0° to 247°, and 303° to 360° (approx.). This area is located at the ice condenser floor where it may be possible for moisture to accumulate against the containment vessel. The risk of potential degradation is considered higher here than for other areas of the containment vessel covered by insulation behind the ice condensers.

Ultrasonic thickness measurements on the above surfaces are performed from the exterior of the containment vessel.

<u>Catawba 2:</u>

1. The following items/areas are examined in accordance with Category E-C, Item E4.11:
    - Examination areas are identical to those on Unit 1, except that the following additional items are also examined:
    - Equipment Hatch latch bolts. These were selected for examination due to conditions found during the performance of Table IWE-2500-1, Category E-G, Item E8.30 examinations.
2. Items/areas that are examined in accordance with Category E-C, Item E4.12 are identical to those on Unit 1.

The applicant further indicated that these areas shall be examined in accordance with IWE-2420(c) until such time that the flaws, areas of degradation, or repairs remain essentially unchanged for three consecutive inspection periods. If other areas containing flaws or degradation are discovered during the performance of IWE examinations, and these areas warrant examination in accordance with Table IWE-2500-1, Category E-C, these other areas shall also be examined in accordance with IWE-2420. The staff find's that this detailed response to RAI B.3.7-2 indicates that the applicant was thorough in identifying the parameters to be monitored. The staff finds the applicant's approach acceptable.

[Acceptance Criteria] Section B.3.7 of the LRA states that this program implements the acceptance criteria specified in Table IWE-3410-1 for each examination category (E-A, E-C, etc.). Areas that do not meet the acceptance standards of Table IWE-3410-1 are be accepted by engineering evaluation, repair, or replacement, as required by IWE-3122. The staff finds the acceptance criteria are consistent with requirements of 10 CFR 50.55a and, therefore, acceptable.

[Corrective Action and Confirmation Process] Section B.3.7 of the LRA provides information on the corrective actions and confirmation process required by the Code. Subsection IWE states that components whose examination results indicate flaws or areas of degradation that do not meet the acceptance standards listed in Table IWE-3410-1 can be considered acceptable if an engineering evaluation indicates that the flaw or area of degradation is nonstructural in nature or has no effect on the structural integrity of the containment, or if such areas are repaired in accordance with IWE-3122.2 and IWE-4000 or replaced in accordance with IWE-3122.3 and IWE-7000. Such areas are subject to the requirements of IWE-2420(b) and (c), and additional examination requirements of IWE-2430, as modified by 10 CFR 50.55a(b)(2)(ix)(D).

When repairs are performed, the requirements of IWE-3124 apply, and the recorded results of reexaminations must demonstrate that the repair meets the acceptance standards set forth in Table IWE-3410-1. For repairs and replacements, the pre-service examination requirements of IWE-2200(d) and the system pressure test requirements of IWE-5000 shall be satisfied, providing additional assurance that the repairs or replacements are acceptable. Since the corrective action and confirmation process is in accordance with the IWE requirements as incorporated by reference in 10 CFR 50.55a, the staff finds them acceptable.

[Operating Experience] Section B.3.7 of the LRA describes the operating experience for McGuire and Catawba containment ISI activities as follows:

> <u>McGuire Operating Experience</u>
> Containment Inservice Inspection Plan - IWE inspections have been performed at McGuire during 1EOC-13, 1EOC-14, 2EOC-12, and 2EOC-13. Inspection results have included the following:
>
> • coatings degradation
> • loss of material due to corrosion of Steel Containment Vessel (SCV) shell, stiffener rings, penetration sleeves, process piping, and bolted connections
> • missing and cracked/separated moisture barriers
>
> Conditions which required reportability in accordance with 10 CFR 50.55a(b)(2)(ix) are documented in letters to the NRC. For example, the most recent McGuire Containment Inservice Inspection that detected conditions requiring reporting is documented in a letter to the NRC dated January 11, 2001.
>
> Prior to implementation of the Containment Inservice Inspection Plan- IWE, inspections were performed in accordance with Appendix J to 10 CFR Part 50. Degradation due to corrosion of the steel containment vessel was identified during these inspections and was documented in LERs 89-20 and 90-06. The corrosion was evaluated and it was determined that the corrosion did not inhibit the ability of the SCV to perform its intended functions. The steel containment vessel was recoated and modifications were made to minimize the potential for reoccurrence.
>
> <u>Catawba Operating Experience</u>
> Containment Inservice Inspection Plan - IWE inspections have been performed at Catawba during 1EOC-11, 1EOC-12, 2EOC-9, and 2EOC-10. Inspection results have included the following:
>
> • coatings degradation
> • loss of material due to corrosion of Steel Containment Vessel (SCV) shell, stiffener rings, penetration sleeves, process piping, and bolted connections
> • missing/damaged parts on equipment hatch latch bolting

• missing and cracked/separated moisture barriers

Conditions which required reportability in accordance with 10 CFR 50.55a(b)(2)(ix) are documented in letters to the NRC. For example, the most recent Catawba Containment Inservice Inspection that detected conditions requiring reporting is documented in a letter to the NRC dated May 1, 2000.

The inspection activities have identified a number of degradations at both stations, all of which have been corrected or determined not to impact the intended function of the component. The variety of items identified by past inspections indicates that this program will be effective in managing aging of the containment.

3.0.3.3.3 FSAR Supplement

A review of the FSAR Supplements in Section 18.2.3 of Appendices A1 and A2 of the LRA for McGuire and Catawba, respectively, indicates that the applicant has described the basic features of Containment ISI Plan - IWE. The staff considers the summary description in UFSAR acceptable.

3.0.3.3.4 Conclusion

The staff has reviewed the information provided in Section B.3.7 of the LRA and the summary description of the inspection activities in Appendix A of the LRA. In addition, the staff considered the applicant’s response to the staff’s RAIs provided in a letter to the NRC dated March 11, 2002. On the basis of this review and the above evaluation, the staff finds that there is reasonable assurance that the Containment ISI Plan - IWE will adequately manage the aging effects such that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.4 Containment Leak Rate Testing Program

Section B.3.8 of the LRA describes the applicant’s containment leak rate testing activities as they are credited for license renewal. The applicant considers these activities to be supplemental to the Containment ISI Plan - IWE program described in Section B.3.7 of the LRA. The containment leak rate tests would detect degradation that had advanced to the point of allowing leakage at the test’s required pressure condition. The staff reviewed Section B.3.8 of the LRA to determine whether the applicant has demonstrated that containment leak rate testing activities will supplement the Section IWE inspections to adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.4.1 Technical Information in the Application

Section B.3.8 of the LRA identifies the loss of material of pressure boundary components and cracking of bellows as aging effects requiring management for the period of extended operation. The purpose of the Containment Leak Rate Testing Program is to supplement the Containment Inservice Inspection Plan- IWE, which implements the provisions of the ASME Code Section XI, Subsection IWE, and is the primary method for detection of aging effects for the steel components of containment. The Containment Leak Rate Testing Program is a performance monitoring program which credits Type A and Type B tests to detect containment pressure boundary components that had degraded to the point of allowing leakage at the test's required pressure condition. The LRA states the following:

> One of the conditions of all operating licenses for water-cooled power reactors is that containment shall meet the leakage test requirements set forth in 10 CFR Part 50, Appendix J. The purposes of these tests are to ensure that:
>
> (a) leakage through the (1) containment and (2) systems and components penetrating containment shall not exceed allowable leakage rate values specified in the Technical Specifications or associated bases, and
> (b) periodic surveillances of containment penetrations and isolation valves are performed.
>
> The Containment Leak Rate Testing Program contains three types of tests: Type A, which are integrated leak rate tests intended to measure the overall leakage rate of the containment; Type B, which are tests intended to measure leakage of containment penetrations whose design incorporates resilient seals and gaskets including airlock door seals and equipment hatch gaskets; and Type C, which are tests to measure containment isolation valve leakage.
>
> Of these three tests, only Type A and Type B are credited for license renewal. The Type A tests would detect severe corrosion of containment pressure boundary steel components that had degraded to the point of allowing leakage at the test's required pressure condition. The Containment Leak Rate Testing Program is implemented per Technical Specifications 3.6.1, Containment, and 5.5.2, Containment Leakage Rate Testing Program.

Based on the information provided in the LRA, the applicant concluded that it is reasonable to expect the continued implementation of the Containment Leak Rate Testing Program to detect loss of material and cracking such that the intended functions of the steel containment vessel, penetrations, bellows, and hatches will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.4.2 Staff Evaluation

Although the applicant describes this program as a supplementary program for aging management of the containment pressure boundary components, the staff considers the successful completion of this program to be a demonstration that the containment and containment components are able to perform their intended function.

The program credits Type A and Type B tests to detect containment pressure boundary components that had degraded to the point of allowing leakage at the test's required pressure condition. In describing the purpose and content of the program, the applicant explicitly excludes the Type C testing from the program as not being credited for license renewal. Type C testing is performed to ensure the integrity of the containment isolation valves. In response to a staff's question related to the exclusion of Type C testing, the applicant argued that the containment isolation valves were active components, and Type C tests, which ensure their leakage characteristics, were not credited for the aging management of these valves. However, they will be performing the tests in accordance with the TS requirements. Based on the understanding that the isolation valves are considered as active components of the containments the staff finds the exclusion of Type C testing from the program acceptable.

The staff's evaluation of the Containment Leak Rate Testing Program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site work management system. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] The scope of the program includes all pressure boundary components including the steel containment vessel, mechanical penetrations, bellows, electrical penetrations, airlocks, hatches, and flanges. The staff considers the applicant's inclusion of these components acceptable.

[Preventive Actions] There are no preventative actions taken as part of this program, and the staff did not identify the need for any preventative actions. This is a performance monitoring test, and the containment ISI program described in Section B.3.7 can be considered as pertinent to the intended function of containment. However, the applicant prefers not to take credit for that program. The staff finds the applicant's position acceptable.

[Parameters Monitored or Inspected] The parameter monitored is the containment leakage rate. The testing is performed to identify leakage that could indicate loss of material and cracking.

The staff agrees that the basic parameters being monitored (i.e., the leakage through the containment pressure boundary components) may indicate loss of materials and cracking when such degradation result in unacceptable leakage through the components. The staff finds the parameters monitored acceptable.

[Detection of Aging Effects] Aging effects are detected through overall leakage during the Type A tests combined with local leakage testing of the penetrations, bellows, and hatches during the Type B tests. Since the Containment Leak Rate Testing Program is used as a supplement to the Containment ISI Plan - IWE, and is only credited with identifying components that have degraded to the point where leakage occurs, the staff finds this acceptable.

[Monitoring and Trending] As described in Section B.3.8 of the LRA, aging effects are detected through overall leakage during the Type A tests combined with local leakage testing of the penetrations, bellows, and hatches during the Type B tests. The Type A tests are performed once every ten years in accordance with Option B, as described in NRC Regulatory Guide 1.163. For McGuire, the Type B tests are performed in accordance with 10 CFR Part 50, Appendix J, Option A requirements. For Catawba, the Type B tests are performed in accordance with 10 CFR Part 50, Appendix J, Option B requirements. All bellows are leak tested in accordance with Technical Specification surveillance requirements. The parameters to be monitored are leakage rates through the primary containment and the systems and components penetrating primary containment. Unacceptable conditions are identified for corrective action and/or further evaluation. The applicant maintains data on the components such as leakage rates, total overall leakage, and containment bypass leakage to ensure that the leakage remains below the allowable limits. Since monitoring and trending will be used to ensure that leakage limits will not be exceeded, the staff finds this acceptable.

[Acceptance Criteria] Section B.3.8 of the LRA states the following:

> The acceptance criteria are defined in Technical Specifications. The containment leakage rate acceptance criterion is less than or equal to 1.0 L_a. L_a is the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting design basis LOCA. During the first plant startup following testing in accordance with this program, the leakage rate acceptance criterion is less than 0.75 L_a for Type A tests.
>
> As left leakage prior to the first startup after performing a required 10 CFR 50, Appendix J, Option A, leakage test is required to be less than 0.6 L_a for combined Type B and C leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit less than or equal to 1.0 L_a.
>
> The space between dual-ply bellows shall be subjected to a low pressure leak test with no detectable leakage. Otherwise, the assembly must be tested with the containment side of the bellows assembly pressurized to P_a and the acceptance criteria is based on the combined leakage rate for all reactor building bypass leakage paths less than or equal to 0.07 L_a.

A review of the Catawba TS indicates that the low pressure associated with the testing of dual-ply bellows varies between 3 and 5 psig. By letter dated January 28, 2002, the staff requested, in RAI B.3.8-1, additional information related to how the combined leakage rate for all reactor building bypass (i.e.0.07L_a) is related to the leakage through the individual bellows, as the bellows will leak into the annulus between the primary containment and the reactor building. In its response dated March 11, 2002, the applicant provided the following:

> The acceptance criterion of 0.07L_a is specified in Technical Specification Surveillance Requirement 3.6.3.8 as the maximum combined leakage rate. This criterion includes the leakage from all penetration bellows. The leakage from the bellows would be added to all other bypass leakage. The total combined leakage is required to be less than 0.07L_a. As such, the test leakage of any individual bellows assembly will be less than 0.07L_a over the extended life of the plant during normal operations as well as during design basis events.

The applicant's allowable combined leakage from all bypass leakage (including those from all penetrations with bellows) will be less than .07La. The staff believes that any significant bellow degradation will be detected by this procedure. Hence, the staff finds the applicant's acceptance criterion for detecting bellow degradation reasonable and acceptable.

[Operating Experience] Section B.3.8 of the LRA states the following:

> Numerous Type A and Type B tests have been performed at McGuire and Catawba over the course of operation. Results have shown that all containment steel components such as the steel containment vessel and flued head penetrations have successfully passed the Type A tests. Results of previous Type B tests have identified leakage of the mechanical bellows as described below.
>
> McGuire Operating Experience:
> McGuire has identified several leaking penetration bellows after twenty years of operation, about half of which are attributable to damage incurred during construction. Some of the original McGuire bellows were repaired/replaced prior to initial plant startup. Main Steam penetration 1M-441 bellows was replaced during refueling outage 1EOC-14 (Spring 2001). The remaining bellows with leakage are within Technical Specification limits. The leakage test results are conservatively added to the overall containment leakage and are included in bypass or non-bypass leakage calculations, as appropriate, with each remaining below allowable Technical Specification limits.
>
> Catawba Operating Experience:

> Catawba has identified a few penetration bellows that failed the low-pressure bellows test. The bellows leakage from these tests was added to the overall leakage and included in the containment bypass leakage calculations. The total overall leakage and containment bypass leakage remains below the allowable Technical Specification limits.

The staff sought to better understand the extent of degradation of containment bellows at McGuire and Catawba containments. By letter dated January 28, 2002, the staff requested, in RAI B.3.8-2, the following information:

> 1. For the McGuire and the Catawba plants, provide the number of bellows where leakages have been found, and the number of bellows that have been replaced, since the beginning of operation of these plants.
>
> 2. For the McGuire and the Catawba plants, provide the number of Duke Class A and Class B bellows that are currently leaking (cracked).
>
> 3. Table 3.5-1 "Aging Management Review Results," indicates that the function of the bellows and mechanical penetrations is to provide a pressure boundary and/or fission product barrier. Provide justification for operating with leaking (cracked) bellows during the period of current operation and the period of extended operation.

In its response dated March 11, 2002, the applicant provided the following response:

> 1. For McGuire, twenty (20) bellows are designated as leaking. One bellows has been replaced at McGuire. For Catawba, three (3) bellows are designated as leaking. No bellows have been replaced at Catawba. For additional information concerning the replaced bellows, reference Appendix B.3.8 of the Application and Response to RAI 3.5-5.
>
> 2. No Class A bellows exist at Catawba or McGuire because there are no Class 1 pipe penetrations through the containment. The answer for question 1 applies to Class B penetrations.
>
> 3. Technical Specification 3.6.1 contains the leakage limits for continued operation. These leakage limits were used in the analysis of off-site doses resulting from accidents. The leakage rate is defined in 10 CFR, Appendix J. The leakage of the bellows remains below the limits specified in Technical Specification 3.6.1.

The above information, and the applicant's response to RAI 3.5-5 (documented in Section 3.5 of this SER), indicate that the applicant is aware of the conditions of containment bellows at McGuire and Catawba plants, and is taking actions to ensure that the existing individual and cumulative leakages from the bellows are within the requirements of the plants' TS.

3.0.3.4.3 FSAR Supplement

The program is described in the Technical Specifications, not in the UFSARs. The description in the Technical Specifications is sufficient, and the staff finds this acceptable.

3.0.3.4.4 Conclusion

The staff has reviewed the information provided in Section B.3.8 of the LRA and applicant's response to the staff's RAIs. On the basis of this review and the above evaluation, the staff finds that there is reasonable assurance that the Containment Leakage Rate Testing Program can effectively supplement the Containment ISI Plan - IWE in managing the effect of aging associated containment components such that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.5 Fire Barrier Inspections

The applicant described its Fire Barrier Inspection program in Section B.3.12.1 of the LRA. The applicant credits this inspection activity with managing the potential aging effects of fire barriers under the scope of license renewal. These inspections are required by SLC 16.9.5. The staff reviewed Section B.3.12.1 of the LRA to determine whether the applicant has demonstrated that fire barrier inspection activities will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.5.1 Technical Information in the Application

Section B.3.12.1 of the LRA describes the fire barrier inspections. The purpose of these inspections is to manage the aging effects of the fire barriers, such as walls, floors, ceilings, and doors, for the period of extended operation. The fire barrier inspections are credited with monitoring the aging effects of loss of material due to corrosion of fire doors, cracking of fire walls, and cracking, delamination, and separation of fire barrier seals. The inspections cover all fire barriers and all sealing devices in fire barrier penetrations.

3.0.3.5.2 Staff Evaluation

The staff’s evaluation of the fire protection program focused on how the program manages the aging effect through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters, monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective action program, while the administrative controls are governed by SLCs and implemented through plant procedures and the site work processes. The staff’s evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] Section B.3.12.1 of the LRA identifies the scope of the fire barrier inspection activities as including all fire barriers, such as walls, floors, ceilings, doors, and all sealing devices in fire barrier penetrations, such as fire doors and penetration seals. All fire barriers and all sealing devices are identified in the implementing procedures and associated drawings. The staff concludes that the applicant included the in-scope fire barriers in the inspections, and finds this acceptable.

[Preventive Actions] There are no preventive or mitigative actions as part of this program, and the staff has not identified the need for any.

[Parameters Monitored or Inspected] The fire barrier inspections require visual examination for loss of material due to corrosion of fire doors, cracking of fire walls, and cracking, delamination and separation of fire barrier penetration seals. The staff finds that the parameters monitored will permit timely detection of the aging effects and are, therefore, acceptable.

[Detection of Aging Effects] The applicant performs visual inspections and functional testing to detect the aging effects described above. Visual inspection and functional tests are capable of detecting the effects of aging because defects would be identified and evaluated using the corrective action before failure would occur. Accordingly, the staff finds visual inspections and functional tests appropriate and acceptable for these inspections.

[Monitoring and Trending] The aging effects are monitored, but not trended. Aging effects are detected through visual examination of the fire barrier, fire doors, and fire barrier penetration seals. All exposed surfaces of each fire barrier is inspected at least once every 18 months in accordance with SLC 16.9.5. Fire doors are visually inspected and functionally tested at least every six months per SLC 16.9.5; 10% of each type of fire barrier penetration seal is inspected at least once every 18 months per SLC 16.9.5. The staff finds the methods and frequency of inspections consistent with industry practice and operating experience. The monitoring frequency is adequate to detect defects, since degradation to failure will not occur within the monitoring interval. Accordingly, the staff finds the monitoring acceptable, and did not identify a need for trending.

[Acceptance Criteria] The acceptance criteria for doors and fire barriers are based on the absence of holes, cracks or gaps through visual examination. The acceptance criteria for fire barrier penetration seals are no visual indications of cracking, shrinkage, or separation of layers of material. In addition, separation from wall and through-holes shall not exceed limits as specified in the procedure.

The LRA stated that “separation from wall and through-holes shall not exceed limits as specified in the procedure.” In RAI B 3.12.1-1, the staff requested a description of the inspection procedures that permit the timely detection of cracking/delamination and separation of the fire barrier penetration seals. The staff also requested the specific limits and the basis for their selection. By letter dated March 11, 2002, the applicant provided the following response:

> Fire penetration seals are inspected on a frequency as directed by Selected Licensee Commitment (SLC) 16.9.5. The limits for the acceptance criteria are specified in the station procedures. The limits are discussed in more detail below.
>
> Crumbling, gouges or voids on fiberboard damming surface shall not exceed one-half (½) inch deep by one (1) inch length and width.
>
> Fiberboard dams should be as flush with the fire barrier and with other pieces of damming board as possible. A maximum one-quarter (1/4) inch gap is acceptable.
>
> For fire barrier penetration seals without permanent damming, the limit of separation of foam from the barrier perimeter or components passing through the seal shall not exceed one-quarter (1/4) inch wide by three (3) inches deep and unlimited length.
>
> For fire barrier penetration seals without permanent damming, gouges or voids on the front side or backside surface of the foam shall not exceed one-half (½) inch deep by one (1) inch length and width.
>
> For fire barrier penetration seals with permanent damming, the limit of separation of foam from the barrier perimeter or components passing through the seal shall not exceed three-quarter (3/4) inch wide by four (4) inches deep and unlimited length.

For fire barrier penetration seals with permanent damming, gouges or voids on the front side or backside surface of the foam shall not exceed three-quarter (3/4) inch wide by four (4) inches deep and unlimited length.

The acceptance criteria are based on experimental tests and engineering analysis as documented in station specifications.

The staff finds the applicant's acceptance criteria and the basis thereof reasonable and acceptable because effects of aging will be detected and will be evaluated using the corrective action program before failure would occur.

[Operating Experience] The operating experience related to the fire barrier inspections at McGuire and Catawba indicates that degradation of fire barrier was detected prior to loss of function. Identified degradation has been associated with installation problems and generally not due to aging. The applicant has documented correspondence with NRC discussing installation deficiencies with fire barrier penetration seals. When a deficiency was noted by the applicant during an audit, additional barrier penetrations were inspected. Generally, these deficiencies were attributed to installation problems. Corrective actions included additional inspections, repair and/or replacement activities. The staff finds that, based on the operating experience, the applicant will effectively maintain the fire barriers during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.5.3 FSAR Supplement

Appendix A of the LRA does not contain a FSAR Supplement for this program; however, the staff finds that the description in SLC 16.9.5 is sufficient and acceptable.

3.0.3.5.4 Conclusion

The staff has reviewed the information provided in Section B.3.12.1 of the LRA and additional information provided by the applicant by letter dated March 11, 2002. On the basis of its review as discussed above, the staff concludes that the continued implementation of the Fire Barrier Inspections provides reasonable assurance that the aging effects will be managed such that the intended functions of the fire barriers will continue to be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.6 Flow Accelerated Corrosion Program

The applicant described its flow accelerated corrosion program in Section 3.14 of Appendix B of the LRA. The staff reviewed the application to determine whether the applicant has demonstrated that the flow accelerated corrosion program will adequately manage the applicable effects of aging in the plant during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.6.1 Technical Information in the Application

The applicant described its flow accelerated corrosion (FAC) program as a condition monitoring program that monitors specific component or material parameters to detect the presence and assess the extent of flow accelerated corrosion. For license renewal, the flow accelerated corrosion program will focus inspections on piping, and is credited for managing loss of material due to flow accelerated corrosion of carbon steel piping, valves, and cavitating venturies within the susceptible regions of the following systems:

- auxiliary feedwater (Catawba)
- auxiliary steam
- boron recycle
- feedwater
- liquid radwaste (Catawba)
- liquid waste recycle (McGuire)
- liquid waste monitor and disposal (McGuire)
- steam generator blowdown recycle (Catawba)
- turbine exhaust (McGuire)

The applicant stated that the only portions of boron recycle, liquid radwaste (Catawba), liquid waste recycle (McGuire), and liquid waste monitor and disposal (McGuire) within the scope of license renewal that are susceptible to flow accelerated corrosion are the supply lines from the auxiliary steam.

The applicant stated that component replacement with a non-susceptible material is initiated as part of the flow accelerated corrosion program. Opportunities to replace components are evaluated by the applicant when related modifications are being performed on a susceptible location or when economic benefit is realized.

Loss of material due to flow accelerated corrosion of carbon steel components is detected by inspection of susceptible component locations. The flow accelerated corrosion program inspections focus on piping. These inspections provide symptomatic evidence of loss of material due to flow accelerated corrosion of other components within the susceptible piping runs. Inspection methods include volumetric examinations using ultrasonic testing and radiography to measure component wall thickness. Visual examinations are also employed when access to interior surfaces is allowed by component design.

The applicant stated that if the calculated component wall thickness at the time of the next outage is projected to be less than the allowable minimum wall thickness with safety margin under the component design code of record, then the component will be repaired or replaced prior to system start-up. The as-inspected component can also be justified for continued service through additional detailed engineering analysis. Specific corrective actions are implemented in accordance with the flow accelerated corrosion program or the applicant's corrective action program. The applicant noted that these programs apply to all components within the scope of the flow accelerated corrosion program.

The flow accelerated corrosion program is not a new program for license renewal. The applicant stated that the program is consistent with the basic guidelines or recommendations provided by EPRI document NSAC-202L and experience has been gained during the operation of McGuire and Catawba.

3.0.3.6.2 Staff Evaluation

The staff's evaluation of the flow-accelerated corrosion program focused on how the program managed aging effects through the effective incorporation of the following 10 elements:

program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program. The staff's evaluation of the applicant's quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] The applicant described the program scope associated with this aging management program as including carbon steel piping, valves, and cavitating venturies within the susceptible regions of the systems listed in Section B.3.14.3 above. The staff finds the scope to be acceptable because the information in the application is comprehensive and includes systems that may be vulnerable to flow accelerated corrosion.

[Preventive or Mitigative Actions] The applicant described the FAC program as a condition monitoring program. Therefore, the flow accelerated corrosion program does not prevent corrosion from occurring or mitigate its effect, but will identify material loss if it is occurring and allow the applicant to take action, including replacement of the component if required. The staff agrees that because the program is designed to identify flow accelerated corrosion, it is not required to take preventive or mitigative actions. The staff finds that based on the information gained from the program, the applicant will be able to take action to repair or replace components if needed.

[Parameters Inspected or Monitored] Loss of material due to flow accelerated corrosion of carbon steel components is detected by inspection of susceptible component locations. The flow accelerated corrosion program inspections focus on piping. These inspections provide symptomatic evidence of loss of material due to flow accelerated corrosion of other components within the susceptible piping runs. Inspection methods include volumetric examinations using ultrasonic testing and radiography to measure component wall thickness. Visual examinations are also employed when access to interior surfaces is allowed by component design. Because visual inspection and the NDE methods to be employed can detect wall thinning due to corrosion, and the methods are consistent with industry practice, the use of these inspection and examination techniques on the components is acceptable.

[Detection of Aging Effects] The applicant stated that, based on the information provided in the Monitoring & Trending section of the LRA, the flow accelerated corrosion program will detect loss of material due to flow accelerated corrosion prior to loss of component intended function. The staff finds that the methods to be employed by the applicant are consistent with current industry practice. In addition, the staff finds that the flow accelerated corrosion program will detect loss of material due to flow accelerated corrosion prior to loss of component intended function. Therefore, the staff finds the applicant's approach for detection of aging effects to be acceptable.

[Monitoring & Trending] The applicant stated that the program is consistent with the basic guidelines or recommendations provided by EPRI document NSAC-202L. Component wall thickness is measured using volumetric examinations such as ultrasonic testing and radiography. Visual examinations are also employed when access to interior surfaces is allowed by component design. Component wall thickness acceptability is judged in accordance with the McGuire and Catawba component design code of record. Defined inspection locations exist in the following systems within the scope of license renewal: auxiliary feedwater (Catawba) and feedwater and steam generator blowdown recycle (Catawba); each contain multiple inspection locations in susceptible regions.

Other defined inspection locations cover several systems that are exposed to the same steam supply environment. Auxiliary steam, boron recycle, liquid radwaste (Catawba), liquid waste recycle (McGuire), and liquid waste monitor and disposal (McGuire) systems are all part of the same steam supply that spans these several systems. The steam is supplied from the auxiliary steam and several inspection locations exist in this run of piping.

The final system within the scope of license renewal falling within the scope of the flow accelerated corrosion program is the turbine exhaust (McGuire). The only in scope portion of turbine exhaust (McGuire) susceptible to flow accelerated corrosion is a few feet of ½" diameter piping. Because of the pipe size, ultrasonic scanning versus ultrasonic testing can be performed on this section of piping in lieu of establishing defined inspection locations. Inspection frequency varies for each location, depending on previous inspection results, calculated rate of material loss, analytical model review, changes in operating or chemistry conditions, pertinent industry events, and plant operating experience. Inspection results are monitored and trended to determine the calculated rate of material loss, to detect changes in operating or chemistry conditions, and schedule for the next inspection. The examination and inspection techniques are consistent with current industry practice and are capable of detecting flow accelerated corrosion prior to loss of component function, therefore the staff finds the monitoring and trending to be acceptable.

[Acceptance Criteria] The applicant stated that using the inspection results and including a safety margin, the projected component wall thickness at the time of the next plant outage must be greater than the allowable minimum wall thickness under the component design code of record. Because the applicant will be capable of detecting, trending and correcting (if necessary) the effects of flow accelerated corrosion before the components lose the ability to perform their intended function, the staff finds this to be acceptable.

[Operating Experience] The applicant performed a review of inspection data for the steam generator blowdown and recycle (Catawba), and auxiliary steam supplies which show minimal loss of material at the inspection locations. The applicant reported that the auxiliary feedwater (particularly Catawba 2) has revealed loss of material in several locations that has resulted in material replacement in significant lengths of piping, illustrating that the program is effective in managing these components. The carbon steel that remains in the system is monitored and evaluated by the applicant as described above. The applicant reported that degradation in the feedwater system has been limited to areas associated with localized velocity. The applicant has replaced these sections of piping with wear-resistant material. The applicant has performed ultrasonic scanning on the turbine exhaust (McGuire) section of piping and minimal loss of material was detected. The applicant reports that no component failures due to flow accelerated corrosion attributed to an inadequate flow accelerated corrosion program have occurred in these systems.

The applicant maintains that this operating experience demonstrates that the when continued into the period of extended operation will be effective in managing flow accelerated corrosion to ensure the component intended pressure boundary function under all current licensing basis design conditions. The staff finds the applicant's aging management activities described above have been effective at maintaining the intended function of the components subject to the flow accelerated corrosion program and can reasonably be expected to do so for the period of extended operation.

3.0.3.6.3 FSAR Supplement

The applicant provided in Appendix A-1 (McGuire) and A-2 (Catawba) new FSAR sections describing the Flow Accelerated Corrosion Program. The information provided for the FSAR is consistent with the program described in Appendix B and no changes are required.

3.0.3.6.4 Conclusion

The staff has reviewed the information in Section B.3.14 of the LRA. On the basis of this review, as above evaluation, the staff concludes that the applicant has demonstrated that the Flow Accelerated Corrosion Program will adequately manage aging effects associated with components subjected to flow accelerated corrosion so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.7 Fluid Leak Management Program

The applicant described its fluid leak management program in Section B.3.15 of Appendix B of the LRA. The fluid leak management program is described as a comprehensive program containing many activities to manage leakage for the entire plant. The program is accomplished by visual surveillance and trending of findings. Systematic walkdowns of the auxiliary and reactor buildings are conducted to identify leakage or evidence of leakage from borated water systems. The staff reviewed the LRA to determine whether the applicant has demonstrated that the fluid leak management program will adequately manage the applicable effects of aging in the plant during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.7.1 Technical Information in the Application

The applicant indicated that the purpose of the fluid leak management program is to manage loss of material due to boric acid wastage of mechanical and structural components within the scope of license renewal that are constructed of carbon steel, low alloy steel, and other susceptible materials that are located in the auxiliary and reactor buildings. The program also manages boric acid intrusion of electrical equipment that is located in proximity to borated water systems.

The fluid leak management program is defined by the applicant as a mitigation program that contains activities developed as part of the applicant's response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The program identifies leaks from borated water systems and initiates investigation and repair. In a letter dated January 28, 2002, the staff requested additional information from the applicant related to provisions for inspecting potentially vulnerable, inaccessible locations for boric acid corrosion. The applicant responded in a letter dated March 15, 2002.

3.0.3.7.2 Staff Evaluation

The staff's evaluation of the fluid leak management program focused on how the program managed aging effects through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program. The staff's evaluation of the applicant's quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] The fluid leak management program includes electrical, mechanical, and structural components within the scope of license renewal that are located in the auxiliary and reactor buildings where exposure to leaks from borated water systems is possible. Mechanical and structural components constructed of carbon steel, low alloy steel, and other susceptible materials are included within the scope of the program.

Mechanical components in the following systems are within the scope of the fluid leak management program:

- Annulus Ventilation
- Auxiliary Building Ventilation
- Auxiliary Feedwater
- Auxiliary Steam
- Boron Recycle
- (Building) Heating Water
- Chemical and Volume Control
- Component Cooling
- Condensate (Catawba)
- Condensate Storage (Catawba)
- Containment Air Release and Addition (Catawba)
- Containment Air Return Exchange and Hydrogen Skimmer
- Containment Hydrogen Sample and Purge (Catawba)
- Containment Purge (Ventilation)
- Containment Spray
- Containment Ventilation Cooling Water (McGuire)
- Control Area Chilled Water
- Control (Room) Area Ventilation
- Feedwater
- (Feedwater Pump) Turbine Exhaust
- Fire Protection (Interior and Exterior)
- Fuel Handling Area (or Building) Ventilation
- Groundwater Drainage
- Hydrogen Bulk Storage
- Ice Condenser Refrigeration
- Instrument Air (McGuire)
- Liquid Radwaste (Catawba)
- Liquid Waste Monitor and Disposal (McGuire)
- Liquid Waste Recycle (McGuire)
- Main Steam

- Main Steam (Supply) to Auxiliary Equipment
- Main Steam Vent to Atmosphere
- Nuclear Service Water
- Reactor Coolant
- Recirculated Cooling Water (Catawba)
- Residual Heat Removal
- Safety Injection
- Spent Fuel Cooling
- Steam Generator Blowdown (Recycle)
- Steam Generator Wet Lay-up Recirculation
- Turbine Building Sump Pump System (Catawba)
- Waste Gas

The staff found that the scope of the fluid leak management program is acceptable because the scope is comprehensive in that it includes the systems, structures, and major components that may be affected by fluid leakage.

[Preventive or Mitigative Actions] The applicant stated that the programmatic implementation of the fluid leak management program is accomplished through visual surveillance and systematic trending of findings. All active leaks are monitored on an appropriate frequency depending on accessibility and rate of leakage. Timely action serves to mitigate loss of material due to boric acid wastage. The staff found that these procedures are adequate because they include all of the activities needed to mitigate the age-related effects that are within scope of this program.

[Parameters Inspected or Monitored] The applicant stated that the systems, structures and components within the auxiliary building and reactor building are inspected for indications of leaks from systems containing borated water. Indications include, but are not limited to, the presence of boron crystals, pitting, and any other degradation beyond normal rust and surface discoloration that may indicate a loss of material. The staff found the parameters monitored, such as boron crystals, pitting, and other degradation, to be acceptable, because they provide direct indication of leakage and potential degradation.

[Detection of Aging Effects] The applicant stated that in accordance with the information provided in the Monitoring & Trending section, below, the fluid leak management program will detect boric acid intrusion and/or loss of material due to boric acid wastage prior to loss of structure or component intended function(s). The staff found the walkdowns to be an acceptable method for identifying leakage problems and the frequency of inspection to be a reasonable time. However, the staff did determine that additional information was needed to complete its review.

By letter dated January 28, 2002, the staff requested, in RAI B.3.15-1, the applicant to describe any provisions of the program for inspecting potentially vulnerable, inaccessible locations. In its response dated March 15, 2002, the applicant stated that a review of containment systems would be conducted to ensure that all potential leak locations would be identified, whether accessible of inaccessible. This understanding of these leakage locations, whether accessible or inaccessible, was an aspect of the initial fluid leak management program when it was established in 1989. The applicant also noted that the program has since been expanded to systems containing boric acid in locations outside of containment that could possibly leak and lead to boric acid wastage. The response was found to be acceptable because the applicant adequately addressed the provision for inspecting potentially vulnerable, inaccessible locations. The applicant will be doing additional work in this area to respond to NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," and NRC Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs." These Bulletins were issued as a result of the Davis-Besse reactor vessel head wastage event, which was attributed to corrosion from boric acid leakage through cracks in the control rod drive mechanism nozzle welds.

The staff and nuclear power industry are pursuing resolution of the issue revealed by the Davis Besse event, and the staff is evaluating potential changes to the requirements governing inspections of Alloy 600 VHP nozzles and PWR upper RV heads (specifically with respect to non-destructive examinations and the ability to detecting cracking in the VHP nozzles prior to loss of material in the upper RV heads). Because this is an emerging issue that has not yet been resolved, but will be resolved during the current license term, consideration of this issue is beyond that scope of this license renewal review, pursuant to 10 CFR 54.30(b). Section 3.1.3.2.2 of this SER provides a more detailed discussion of this emerging issue.

Based on its review of the Fluid Leak Management program, the staff believes that the program provides a reasonable means of detecting aging before loss of intended function of the affected structures, systems and components.

[Monitoring and Trending] The applicant stated that walkdowns of the auxiliary and reactor buildings are conducted at the start of each refueling outage for the purpose of identifying leakage or evidence of leakage from borated water systems. Information on all leaks (e.g., equipment, system, leakage type and rate) is captured in the fluid leak management database to facilitate trending of leakage, if necessary. The fluid leak management database is periodically reviewed to identify adverse trends and opportunities to improve maintenance, engineering, and operation practices. The staff found the applicant's approach of monitoring activities to be acceptable because it is based on methods that are sufficient to provide predictability of the extent of degradation so that timely corrective or mitigative actions are possible.

[Acceptance Criteria] The applicant described the acceptance criteria as finding the external surfaces of structures and components within the scope of the fluid leak management program, including surroundings (e.g., insulation and floor areas), to be free from pitting and corrosion, abnormal discoloration or accumulated residues that may be evidence of leakage from proximate borated water systems. Because the degradation is detectable by visual inspection, the staff found this to be an acceptable set of acceptance criteria.

[Operating Experience] The applicant stated that the fluid leak management databases for Catawba and McGuire were searched for boric acid leaks that have been identified through the implementation of the fluid leak management program. The applicant stated that the majority of the leaks were identified as inactive with only evidence of past leakage. No evidence of loss of material has been found on either the leaking components or on other components in the area of any identified leak. Corrective actions, which were implemented through the applicant's work management system, included cleaning the area around the leak and either tightening bolted closures or containing the leak. The applicant concluded that the frequencies of inspections have been demonstrated to be adequate to identify leaks before any loss of material is a concern, and thus before loss of component intended function(s). The staff found that the applicant has demonstrated that the fluid leak management program has been effective in managing the effects of boric acid wastage on the intended function of reactor components.

3.0.3.7.3 FSAR Supplement

LRA Appendix A-1, Section 18.2.11 provides the applicant's proposed FSAR Supplement describing the McGuire fluid leak management program. Appendix A-2, Section 18.2.10 provides the description of the Catawba Fluid Leak Management Program. These descriptions are consistent with the information provided in Appendix B, Section B.3.15, and are therefore found to be acceptable.

3.0.3.7.4 Conclusion

The staff has reviewed the information in Section B.3.15 of the LRA and the applicant's response to the staff's RAIs. On the basis of this review and the above evaluation, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the fluid leak management program will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.8 Galvanic Susceptibility Inspection

The applicant described its galvanic susceptibility inspection program in Section B.3.16 of Appendix B of the LRA. The staff reviewed the LRA to determine whether the applicant has demonstrated that the galvanic susceptibility inspection program will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.8.1 Technical Information in the Application

Section B.3.16 of the LRA describes a new program the applicant intends to implement to characterize any loss of material due to galvanic corrosion from exposure to gas, unmonitored treated water, and raw water environments. Galvanic corrosion could occur in the following systems:

- condenser circulating water
- containment ventilation cooling water (McGuire only)
- diesel generator room sump pump
- exterior fire protection
- interior fire protection
- liquid radwaste (Catawba only)
- nuclear service water
- waste gas

The galvanic couples in these systems are carbon steel, cast iron, and ductile iron (anodes) coupled to copper alloys or stainless steel (cathodes) and copper alloys (anodes) coupled to stainless steel (cathode). Copper alloys are comprised of copper, brass, bronze and copper-nickel. In galvanic couples, the loss of material occurs in the anodes.

The applicant's galvanic susceptibility inspection program is a one-time inspection program that will examine a select set of carbon steel-stainless steel couples at each site using a volumetric examination technique. As an alternative, visual examination will be used if access to internal surfaces becomes available. The susceptibility and aggressiveness of galvanic corrosion is determined by the material position on the galvanic series and the characteristics of the surrounding environment. Since inspection of all couples is impractical, certain locations will be inspected where galvanic corrosion is more likely to occur. These more susceptible locations are where the materials are the farthest apart on the galvanic series surrounded by the most corrosive of the three environments identified above. For the couples noted above, carbon steel and stainless steel are the farthest apart on the galvanic series and raw water is the most corrosive environment.

3.0.3.8.2 Staff Evaluation

The staff's evaluation of the applicant's AMPs related to the galvanic susceptibility inspection program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope] The scope of the program includes all galvanic couples exposed to gas, unmonitored treated water, and raw water environments in the systems noted above. In this program, the applicant determines acceptability of the components subject to galvanic corrosion for service during the period of extended operation. This determination will be achieved by performing inspection of selected components. The program will inspect a select set of carbon steel-stainless steel couples at each site using a volumetric examination technique. The sample will purposely contain components expected to be most susceptible to galvanic corrosion. The sample will consist of carbon steel components coupled with components made from stainless steel and exposed to a raw water environment. Since these materials are the farthest apart on the galvanic series and in the most aggressive environment, the highest potential for galvanic corrosion is expected. The staff finds the scope of this AMP acceptable because the inspections will be of the most susceptible material and the inspection results will be applied to other couples in the systems, as appropriate.

[Preventive or Mitigative Actions] The applicant indicated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff agrees that the purpose of the program is to visually examine those areas within the scope of the program and take corrective action where required and therefore, preventive or mitigative actions are not required.

[Parameters Monitored or Inspected] The applicant stated that the parameter inspected by the program is pipe wall thickness, as a measure of loss of material, of carbon steel-stainless steel couples exposed to raw water environments. The staff finds the parameter monitored to be acceptable because pipe wall thickness will provide a clear indication of loss of material. In addition, the techniques to be used are consistent with current industry practice and are capable of identifying pipe wall thinning and are therefore acceptable.

[Monitoring and Trending] There are no activities in the galvanic susceptibility inspection program with regard to monitoring and trending. The staff did not identify the need for such.

[Detection of Aging Effects] The applicant stated that this is a one-time inspection that will detect the presence and extent of any loss of material due to galvanic corrosion. The wall thickness inspection of the representative sample will determine loss of material due to galvanic corrosion and assess the likelihood of the impact of this aging effect on the components in the portion of the plant included in the LRA. The staff finds this approach acceptable because it bounds galvanic corrosion rates occurring in other components in the plant and therefore, provides meaningful detection of age-related damage caused by galvanic corrosion.

With respect to the inspection timing, the applicant stated that this one-time inspection will be completed by June 12, 2021, at McGuire and by December 6, 2024, at Catawba. The staff finds this inspection schedule acceptable because, if present, galvanic corrosion is expected to be a slow acting corrosion mechanism for the affected components in these systems; therefore, the staff finds the use of a one-time inspection adequate.

[Acceptance Criteria] The acceptance criterion for the program is no unacceptable loss of material that could result in a loss of the component intended function(s) as determined by engineering evaluation. By letter dated January 28, 2002, the staff requested, in RAI B.3.16-2, additional information from the applicant regarding the acceptance criteria to be used to define “unacceptable loss of material.” In its reply dated March 15, 2002, the applicant indicated that if evidence of loss of material is observed during the initial inspection, a problem report would be developed in accordance with the Problem Investigation Process of Nuclear System Directive 208.

The Problem Investigation Process is a formalized process for documenting engineering evaluations of plant problems that would include the assessment of the severity of the observed degradation, the need for corrective actions, the need for further inspections of other locations, and the need for future inspections or programmatic oversight. The applicant also indicated that criteria such as ASME Code requirements, additional inspection results, and operating experience may be used to assess the severity of the degradation and the need for corrective actions. Any criteria or analysis methods involved in determining the severity of the degradation and the need for corrective action will be developed at the time of the evaluation and will be a part of the problem report.

The applicant believes it is premature to specify analysis methodology and the actual criteria or analysis methods for determining severity and the need for corrective actions for an inspection that will occur 15 to 20 years from now. The staff agrees with the applicant’s position. Since the applicant indicated that criteria such as ASME Code requirements, additional inspection results, and operating experience may be used to assess the severity of the degradation and the need for corrective actions, the staff finds the applicant’s response to be acceptable.

[Operating Experience] The applicant indicated that there was no operating experience for the galvanic susceptibility inspection program at McGuire and Catawba. However, because of the possibility of this type of corrosion, it established a one-time inspection program. In this program, Duke will determine acceptability of the components subjected to galvanic corrosion for service during the period of extended operation. This determination will be achieved by performing inspection of selected components. The sample will purposely contain components expected to be exposed to the highest rates of galvanic corrosion. Although the Galvanic Susceptibility Inspection is a new program, with which the applicant has no operating experience, the applicant recognizes that galvanic corrosion is possible. Since the applicant will sample (as a one-time inspection) components expected to be exposed to the highest rates of galvanic corrosion, the staff finds the applicant's approach acceptable.

3.0.3.8.3 FSAR Supplement

Appendix A-1, Section 18.2.12 contains the McGuire FSAR Supplement describing the Galvanic Susceptibility Program and Appendix A-2, Section 18.2.11 contains the Catawba FSAR Supplement for this program. The program descriptions are consistent with the material contained in Section B.3.16 and are therefore acceptable to the staff.

3.0.3.8.4 Conclusion

The staff has reviewed the information in Section B.3.16 of the LRA. On the basis of this review and the applicant's response to the staff's RAI, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with components subjected to galvanic corrosion will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.9 Common Heat Exchanger Activities

In Section B.3.17 of Appendix B of the LRA, the applicant described the performance testing and the preventive maintenance activities associated with heat exchangers in several different systems. The staff's evaluations of system-specific AMPs is provided in the SER sections indicated as follows:

- component cooling system - Section 3.3.5.2
- containment spray systems - Section 3.2.4.2
- diesel generator engine cooling water system - Section 3.3.12.2
- control area chilled water system - Section 3.3.8.2
- diesel generator starting air (Catawba only) - Section 3.3.17.2

The following are common AMPs:

- pump motor air handling units (McGuire only)
- pump oil coolers (McGuire only)

The staff reviewed the LRA to determine whether the applicant has demonstrated that these common heat exchanger programs will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff's evaluation of these common AMPs is provided in the following Sections 3.0.3.9.1 and 3.0.3.9.2.

3.0.3.9.1 Heat Exchanger Preventive Maintenance Activities - Pump Motor Air Handling Units

The applicant described its preventive maintenance activities-pump motor air handling units program in Section B.3.17.6 of Appendix B of the LRA. Although this AMP is credited for monitoring aging effects of heat exchanger tubes associated with the auxiliary building ventilation system for McGuire only, it is considered a common AMP that is shared among pump motor air handling units in the containment spray, residual heat removal, and fuel pool cooling systems. The staff reviewed the LRA to determine whether the applicant has demonstrated that this program will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3). This program is applicable only to McGuire because Catawba has shutdown panel area air conditioning unit condenser tubes, tubesheets, and shells in place of the McGuire containment spray pump motor air handling unit tubes and plenum assembly.

The aging effects of the subject Catawba components include fouling and loss of material, which are managed by the chemistry control program, fluid leak management program, and inspection program for civil engineering structures and components.

3.0.3.9.1.1 Technical Information in the Application

As described in the LRA, the purpose of the heat exchanger preventive maintenance activities - pump motor air handling units program is to manage loss of material and fouling of copper heat exchanger tubes that are exposed to raw water. The heat exchanger preventive maintenance activities - pump motor air handling units program is a new condition monitoring program that will detect the presence and assess the extent of material loss that can affect the pressure boundary function and will periodically clean the heat exchanger tubes to manage fouling. While fouling is managed currently by cleaning, this comprehensive program to manage both loss of material and fouling is a new plant program for license renewal.

3.0.3.9.1.2 Staff Evaluation

The staff evaluated the applicant's submittal on the Heat Exchanger Preventive Maintenance Activities - Pump Motor Air Handling Units focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope] The scope of Heat Exchanger Preventive Maintenance Activities - Pump Motor Air Handling Units includes the tubes in the following McGuire heat exchangers of the Auxiliary Building Ventilation System:

- Containment Spray Pump Motor Air Handling Units
- Residual Heat Removal Pump Motor Air Handling Units
- Fuel Pool Cooling Pump Motor Air Handling Units

The staff found the scope of the program to be acceptable because it includes those components important to the system function and will allow identification of fouling which can affect the heat transfer function of the component.

[Preventive or Mitigative Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff agrees with the applicant because the purpose of the program is to detect and assess the extent of material loss and fouling, not to prevent such loss or fouling.

[Parameters Monitored or Inspected] The applicant stated that the heat exchanger preventive maintenance activities - pump motor air handling units program will inspect the heat exchanger tubes to provide an indication of loss of material. Fouling of the internal portions of the heat exchanger tubes exposed to raw water is managed by tube cleaning. Routine differential pressure testing determines when cleaning is required. The staff found the parameters monitored to be acceptable since the parameters evaluated and the methods used are comparable to industry practice and will result in detecting material loss before loss of component function.

[Detection of Aging Effects] The applicant stated that in accordance with the information provided in the LRA under the Monitoring and Trending section, the heat exchanger preventive maintenance activities - pump motor air handling units program will detect loss of material prior to loss of the component intended pressure boundary function. The program will also manage fouling prior to loss of heat transfer function. The staff's review found this acceptable, because the applicant performs non-destructive or destructive testing methods, which are standard industry methods, and the staff agrees that the program is capable of detecting and correcting aging degradation before loss of component function.

[Monitoring and Trending] The applicant stated that the heat exchanger preventive maintenance activities - pump motor air handling units program will perform either a destructive or non-destructive examination of one of the twelve total cooling coils within the scope of the program. The examination method will permit inspection of the inside surfaces of the tubes for loss of material.

The applicant stated that the selection of the specific inspection locations will take into consideration the normal operating environments. The containment spray pump motor air handling units and the residual heat removal pump motor air handling units are normally isolated. The fuel pool cooling pump motor air handling units are normally in service and should experience the most susceptible service environment for loss of material to occur. One of the fuel pool cooling pump motor air handling units cooling coils will therefore be examined as a representative of the total program scope. Tube cleaning is performed to manage fouling of the heat exchanger tubes at least once every two years. No actions are taken as part of this activity to trend inspection or test results. This new comprehensive program will be implemented following issuance of renewed operating licenses for McGuire Nuclear Station and by June 12, 2021 (the end of the initial license of McGuire 1).

The staff's finds that the monitoring activities will allow the applicant to identify fouling and/or loss of material. The staff has reviewed the selection criteria used by the applicant to determine the appropriate sampling locations and finds the sample to be appropriate as a leading indicator for other components in the program because they will be sampling the system most likely to experience aging effects.

[Acceptance Criteria] The applicant stated that the acceptance criterion for the heat exchanger preventive maintenance activities - pump motor air handling units program is no unacceptable loss of material of the tubes that could result in a loss of the component intended function(s) as determined by engineering evaluation. The staff does not consider this an adequate acceptance criterion for the heat preventive maintenance activities AMP. In addressing the acceptance criteria, the staff requests the applicant to specify parameters with quantitative limits (e.g., percent of flow blockage or percent of loss of heat transfer). The staff also notes that a similar finding is documented in Sections 3.0.3.9.2.2, 3.2.4.2.2, 3.3.5.2.2, 3.3.8.2.2, 3.3.12.2.2, and 3.3.17.2.2 of the SER. Therefore, as it applies to this section (Section 3.0.3.9.1.2) of the SER, this issue is characterized as open item 3.0.3.9.1.2-1(a). Similar findings are characterized as open items 3.0.3.9.1.2(b), 3.0.3.9.1.2(c), 3.0.3.9.1.2(d), 3.0.3.9.1.2(e), 3.0.3.9.1.2(f), and 3.0.3.9.1.2(g) in Sections 3.0.3.9.2.2, 3.2.4.2.2, 3.3.5.2.2, 3.3.8.2.2, 3.3.12.2.2, and 3.3.17.2.2 of this SER, respectively.

The applicant stated that the acceptance criteria for the performance testing activities is the established differential pressure value that ensures fouling does not prevent the heat exchangers from performing their design basis function. The staff found the acceptance criteria to be acceptable, because the testing method will detect degradation of the heat exchangers and will allow corrective action to be taken before fouling can result in loss of the design function.

[Operating Experience] The applicant stated that the heat exchanger preventive maintenance activities - pump motor air handling units program tube examination is a new activity for which there is no plant-specific operating experience. The applicant reported that there have been no age-related tube failures in any of the cooling coils within the scope of this program, as confirmed through periodic leak detection. A few tube leaks have been detected and repaired, but were determined not to be age-related. Periodic tube cleaning has been performed by the applicant in the past. Routine differential pressure testing determines when cleaning is required. This method has been effective in managing fouling of the heat exchanger tubes and will continue to be performed during the period of extended operation.

The staff finds that, although this is a new program, prior experience in periodic leak detection and other testing have provided a basis for concluding that the program will be an effective method of monitoring the components during the period of extended operation. Therefore, the staff agrees that past operating experience can be relied on to provide the basis for this new program.

3.0.3.9.1.3 FSAR Supplement

In Appendix A-1, Section 18.2.13, the applicant has provided a proposed FSAR Supplement for the McGuire Station. This program will be applied only at McGuire. The staff has reviewed this information and finds it to be consistent with the information provided in Appendix B, Section B.3.17 and is therefore acceptable.

3.0.3.9.1.4 Conclusion

The staff has reviewed the information in Section B.3.17.7 of the LRA. On the basis of this review and the above evaluation, with the exception of open item 3.0.3.9.1.2-1(a) pertaining to acceptance criteria for the heat exchanger preventive maintenance activities, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the preventive maintenance activities - pump motor air handling units heat exchanger program will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.9.2 Heat Exchanger Preventive Maintenance Activities - Pump Oil Coolers

The applicant described its preventive maintenance activities of the pump oil coolers heat exchangers in Section B.3.17.7 of Appendix B of the LRA. Although this AMP is credited for monitoring aging effects of heat exchanger tubes associated with the nuclear service water system for McGuire only, it is considered a common AMP that is shared among oil coolers for pumps associated with the charging (chemical and volume control system) and safety injection systems. The staff reviewed the LRA to determine whether the applicant has demonstrated that this program will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3). This program is only applicable to McGuire because Catawba has annubars and other tubing components instead of the McGuire centrifugal charging pump bearing oil cooler tubes and speed reducer oil cooler tubes. The aging effects of the subject Catawba components include loss of material and cracking, which are managed by the preventive maintenance activities - condenser circulating water system internal coating inspection program, service water piping corrosion program, and fluid leak management program.

3.0.3.9.2.1 Technical Information in the Application

In Section 3.17.7 of Appendix B of the LRA, the applicant provided a discussion of the Heat Exchanger Preventive Maintenance Activities - Pump Oil Coolers. This program is to be conducted only at McGuire and is applicable only to the McGuire Nuclear Station. The applicant stated that the purpose of the program is to manage loss of material and fouling of copper-nickel heat exchanger tubes that are exposed to raw water. The Heat Exchanger Preventive Maintenance Activities - Pump Oil Coolers is a new condition monitoring program that monitors specific component parameters to detect the presence and assess the extent of material loss that can affect the pressure boundary function and periodically cleans the heat exchanger tubes to manage fouling. While the applicant currently manages fouling by periodic cleaning, this comprehensive program to manage both loss of material and fouling is a new plant program for license renewal.

3.0.3.9.2.2 Staff Evaluation

The staff’s evaluation of the applicant’s submittal of the heat exchanger preventive maintenance activities-pump oil coolers program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope] The applicant stated that the scope of the heat exchanger preventive maintenance activities - pump oil coolers program consists of the tubes in the following McGuire heat exchangers of the nuclear service water system:

- centrifugal charging pump bearing oil cooler
- centrifugal charging pump speed reducer oil cooler
- reciprocating charging pump bearing oil cooler
- reciprocating charging pump fluid drive oil cooler
- safety injection pump bearing oil cooler

The staff found the scope of the program to be acceptable because it includes those components important to the system function and will allow identification of fouling which can affect the heat transfer function of the component.

[Preventive or Mitigative Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff agrees with the applicant because the purpose of the program is to detect and assess the extent of material loss and fouling, not to prevent such loss or fouling.

[Parameters Monitored or Inspected] As described in the application, the heat exchanger preventive maintenance activities - pump oil coolers program inspects the heat exchanger tubes to provide an indication of the loss of material. Fouling of the internal portions of the heat exchanger tubes exposed to raw water is managed by routine cleaning. The staff found that because the inspections will be performed and allow for corrective actions to be taken prior to the loss of the component's function, the parameters monitored or inspected are adequate to meet the stated purpose of the program.

[Detection of Aging Effects] The applicant stated that the information provided under the Monitoring & Trending section in the LRA, demonstrated that the heat exchanger preventive maintenance activities - pump oil coolers program will detect the loss of material prior to the loss of the component's intended pressure boundary function. The program will also manage fouling prior to the loss of the heat transfer function. The staff found that this approach is acceptable because the program is capable of identifying the aging effects prior to the loss of the component's intended function.

[Monitoring & Trending] The applicant stated that the heat exchanger preventive maintenance activities - pump oil coolers program will perform eddy current testing on the heat exchanger tubes to measure wall thickness in order to detect areas with loss of material. NDT will be performed on 100 percent of the tubes. The staff found this one-time inspection acceptable because following the initial inspection, the applicant will establish an appropriate frequency for follow up inspections based on inspection results. Tube cleaning is performed to manage fouling of the heat exchanger tubes every two to three years. No actions are taken as part of this activity to trend inspection or test results. This new comprehensive program will be implemented following issuance of renewed operating licenses for McGuire and by June 12, 2021 (the end of the initial license of McGuire 1).

The staff agrees that the inspection activities are capable of identifying aging effects. Because the initial 100 percent NDT inspection will provide information on the current state of all tubes in the program, the applicant will be capable of detecting and correcting any problems prior to the loss of the component's function.

[Acceptance Criteria] The applicant stated that the acceptance criterion for the heat exchanger preventive maintenance activities - pump oil coolers eddy current testing activity is no unacceptable loss of material of the tubes that could result in a loss of the component intended function(s) as determined by engineering evaluation. The staff does not consider this an adequate acceptance criterion for the heat preventive maintenance activities AMP. In addressing the acceptance criteria, the staff requests the applicant to specify parameters with quantitative limits (e.g., percent of flow blockage or percent of loss of heat transfer). Because the same finding was identified for the heat exchanger preventive maintenance activities - pump motor air handling units, as documented in Section 3.0.3.9.1.2 of this SER, this issue is characterized as open item 3.0.3.9.1.2-1(b).

[Operating Experience] The applicant stated that the heat exchanger preventive maintenance activities - pump oil coolers eddy current testing is a new activity for which there is no plant-specific operating experience. Eddy current examinations are volumetric methods accepted by the industry to be effective for detecting age-related degradation in heat exchanger tubes. The applicant stated that there have been no tube failures in any of the heat exchangers within the scope of this program, as confirmed through periodic leak detection.

The applicant has performed periodic tube cleaning in the past. Cleaning every two to three years has been effective in managing fouling of the heat exchanger tubes. The applicant has committed to continue this periodic tube cleaning during the period of extended operation.

The staff finds that, because this new program is capable of identifying loss of material or fouling in the heat exchangers included in the scope of the program, it is an acceptable method of meeting the program objectives. Although there is no past operating experience with this program, activities to inspect the condition of the tubes in the program have been conducted in the past with acceptable results. The applicant will be using methods that are widely accepted in the industry. Therefore, the staff finds this approach to be acceptable.

3.0.3.9.2.3 FSAR Supplement

In Appendix A-1, Section 18.2.13, the applicant has provided a proposed FSAR Supplement for McGuire. This program will be applied only at McGuire. The staff reviewed this information and finds it to be consistent with the information provided in Appendix B, Section B.3.17 and is therefore acceptable.

3.0.3.9.2.4 Conclusion

The staff has reviewed the information in Section B.3.17.7 of the LRA. On the basis of this review and the above evaluation, with the exception of open item 3.0.3.9.1.2-1(b) pertaining to acceptance criteria for the heat exchanger preventive maintenance activities, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the preventive maintenance activities - pump oil coolers heat exchangers program will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.10 Inservice Inspection Plan

The applicant described its Inservice Inspection (ISI) Plan in Section B.3.20 of the LRA. Throughout the service life of nuclear power plants, Class 1 components and associated Class 1 supports must meet the requirements set forth in Section XI of the ASME Code and Addenda that are incorporated by reference in 10 CFR 50.55a(b).

Inservice examinations and system pressure tests conducted during successive 120-month inspection intervals, following the initial 120-month ISI interval, must comply with the requirements of the latest edition and addenda of the Code incorporated by reference in 10 CFR 50.55a(b) twelve months prior to the start of the 120-month inspection interval, subject to the limitations and modifications, such as code editions and addenda, as listed in paragraph 10 CFR 50.55a(b)(2)(i).

The period of extended operation will contain the fifth and sixth ISI intervals. The ISI Plan for each interval of the renewal license period of extended operation for McGuire and Catawba will comply with 10 CFR 50.55a (g)(4)(ii) except that if an examination required by the Code or Addenda is determined to be impractical, then the Applicant will submit a relief request to the Commission in accordance with the requirements contained in 10 CFR 50.55a (g)(5)(iii) and (iv), for Commission evaluation, as required by 10 CFR 50.55a (g)(6)(i).

The Integrated Plant Assessment performed for McGuire and Catawba credited the ASME Section XI Code requirements for ISI of Class 1 components, Class 2 portions of the steam generators and associated supports as shown in Tables IWB 2500-1 and IWC-2500-1 of the 1989 Edition of ASME Section XI, including mandatory Appendices VII and VIII. Appendix VIII is in accordance with the 1995 Edition through 1996 Addenda. At present, the code of record for the McGuire and Catawba units is the 1989 Edition, no addenda, as described in the second interval ISI Plan for McGuire and Catawba.

3.0.3.10.1 Technical Information in Application

The ISI Plan is required by 10 CFR Part 50. The applicant notes that the program described in the LRA has been in use at the plants since initial licensing. The applicant states that McGuire and Catawba are currently in the second inspection interval, with more than 20 years experience at McGuire and 15 years at Catawba with the ISI Plan.

The ISI Plan includes the following inspections and activities:

- ASME Section XI, Subsections IWB and IWC (secondary side of steam generators) Inspections
- ASME Section XI, Subsection IWF Inspections
- McGuire 1 cold leg elbow
- Small bore piping

The LRA describes the various components inspected in each of the inspections listed above. The applicant concludes that the results to date show that the ISI Plan is capable of identifying aging effects and the continued implementation of the program provides reasonable assurance that the aging effects will be managed and that the piping and component supports will continue to perform their intended function for the period of extended operation.

3.0.3.10.2 Staff Evaluation

The staff's evaluation of the ISI Plan as it is credited for license renewal focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions, confirmation process, and administrative controls are implemented in accordance with Code requirements through site procedures and processes. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining elements are discussed below.

[Program Scope] The scope of the ISI Plan includes the following:

- ASME Section XI, Subsections IWB and IWC Inspections: All Class 1 pressure-retaining components and their integral attachments are included in the scope of the ASME Section XI, Subsections IWB and IWC Inspections. In addition, Subsection IWC, Examination Categories C-A, C-B, C-C, and C-H cover the Class 2 portions of the steam generators.
- ASME Section XI, Subsection IWF Inspections: The scope is specified in IWF-1210 and includes ASME Class 1, 2, and 3 piping supports and component supports.
- McGuire 1 Cold Leg Elbow: Reduction in fracture toughness due to thermal embrittlement can be an aging effect for certain types of cast austenitic stainless steel in locations where temperatures continuously exceed 482ºF. As a result of an evaluation of susceptible components by the applicant, only the McGuire 1, Loop B cold leg elbow exceeds the NRC-established threshold and is susceptible to thermal embrittlement, requiring aging management for license renewal.
- Small bore piping: Small bore piping is defined as piping less than 4-inch nominal pipe size. This piping does not receive volumetric inspection in accordance with ASME Section XI, 1989 Edition, Examination Category B-J or B-F. Cracking has been identified as an aging effect requiring programmatic management for reactor coolant system small bore piping for the period of extended operation. A risk-informed method to select Class 1 piping welds for inspection in lieu of the requirements specified in ASME Section XI, Table IWB-2500-1, Examination Category B-J and B-F, has been approved for use at McGuire during the third and fourth ISI intervals. The applicant

plans to complete a similar review for Catawba, as documented in its FSAR supplement. This review will be performed based on WCAP 14572, Revision 1, which requires that the McGuire and the Catawba risk-informed submittals provide equivalent or better risk coverage for the risk-informed inservice inspection scope. The review will be performed before the period of extended operation begins.

The staff finds the scope of this aging management program is relatively comprehensive and includes the systems, structures, and components that are required to be included in the ASME ISI Plan. However, the staff believes that the applicant should perform a volumetric examination of a sample of small bore Class-1 piping less than 4-inches in diameter (refer to the discussion of open item 3.0.3.10.2-1 associated with the Detection of Aging Effects element below).

[Preventive or Mitigative Actions] The applicant describes the ISI Plan as a condition monitoring program and does not include actions to prevent aging effects or mitigate aging degradation. The staff considers the ISI Plan to be a means of detecting, not preventing, aging and therefore agrees that there are no preventive actions required.

[Parameters Inspected or Monitored] Section B.3.20 of the LRA states that the following items are included in the system:

- ASME Section XI, Subsections IWB and IWC Inspections Class 1 component welds, integral attachments, piping welds, bolted closures and supports as well as the Class 2 pressure boundary portions of the steam generators (welds and welded attachments) are inspected for cracking and loss of material.
- ASME Section XI, Subsection IWF Inspections: All Class 1 pressure-retaining components and their integral attachments are included in the scope of the *ASME Section XI, Subsections IWB and IWC Inspection*s. In addition, Subsection IWC, Examination Categories C-A, C-B, C-C, and C-H cover the Class 2 portions of the steam generators.
- McGuire 1 cold leg elbow: The applicant proposes the use of an augmented inspection with elements from Code Case N-481 to manage reduction of fracture toughness by thermal embrittlement for the affected elbow during the period of extended operation.
- Small bore piping: The applicant has been approved to use a risk-informed approach to identify risk significant segments within the reactor coolant system and select Class 1 piping welds for inspection at McGuire, and plans to submit a similar plan for Catawba.

The staff reviewed the information provided in the LRA and agrees that, because the methods used in the ISI Plan are capable of detecting loss of material in the inspected systems and components, these inspection techniques are acceptable.

[Detection of Aging Effects] The applicant stated that the ISI Plan has demonstrated the capability to detect loss of material for Class 1, 2, and 3 piping and component supports prior to loss of structure or component intended functions. The staff agrees that the program, which is consistent with current industry practice and ASME requirements, is capable of detecting aging effects and is acceptable. However, the staff believes that volumetric examination of a sample of small-bore Class-1 piping is needed to demonstrate that the effects of aging are being adequately managed. Volumetric examination techniques provide a demonstrated capability and a proven industry record to permit detection and sizing of significant cracking and flaws in piping weld and base material. The sample of affected welds selected for inspection should be based upon piping geometry, pipe size and flow conditions, and the inspection should be performed by qualified personnel using approved station procedures. Therefore, this is characterized as open item 3.0.3.10.2-1.

[Monitoring and Trending] The applicant stated that the required examinations are directed by the ISI Plan. The extent and frequency of examinations are specified in ASME Section XI. Aging effects are detected through visual examination. The complete inspection scope is repeated every 10-year inspection interval. The staff considers the ASME Code requirement to be an acceptable monitoring method and agrees that no actions need be taken as part of this program to trend inspection or test results.

[Acceptance Criteria] The applicant stated that flaws detected during examination are evaluated by comparing the examination results to the acceptance standards established in ASME Code, Section XI. Unacceptable indications require detailed analyses, repair, or replacement. The ASME Code, Section XI, acceptance standards ensure that all Service Conditions (A-D) are protected by maintaining the safety margin of the component throughout the service life of the component. When evaluating an operating component for an indication that exceeds the allowable acceptance standards established in IWB-3500 and IWC-3500, Section XI requires the use of the original safety margins for all operating conditions (i.e., normal, upset, emergency and faulted conditions). The safety margins vary for specific cases (e.g., component, geometry, etc.) but are always consistent or conservative with respect to the original design margins. The staff accepts the flaw evaluation methodology of the Code as the industry standard and, therefore, the staff finds the management of aging effects based on the Code criteria to be acceptable.

[Operating Experience] The results of the ASME Section XI Inspections for McGuire and Catawba are submitted to the NRC. The applicant reports that McGuire and Catawba are currently in the second inspection interval and have more than 20 years at McGuire and 15 years at Catawba of operating experience with the inspection of Class 1 components as well as the Class 2 pressure boundary portions of the steam generators. The applicant stated that the inspections which have been completed to date have found very few flaws which do not meet the acceptance criteria and which required further evaluation in accordance with ASME Code, Section XI.

The staff acknowledges that during V. C. Summer refueling outage 12 (October, 2000), a through-wall crack was identified in the reactor vessel hot leg piping. Specifically, the crack was located in the first weld between the reactor vessel nozzle and the "A" loop hot leg piping, approximately 3 feet from the reactor vessel and 7 degrees clockwise from the top dead center of the weld (as viewed from the centerline of the reactor vessel). The weld was fabricated from Alloy 82/182 material. The licensee’s metallurgical evaluation showed the crack was axially oriented with a length about 2.5 inches and was connected to a small weep hole on the out side diameter surface of the weld. The failure mode was determined to be primary water stress corrosion cracking and the root cause of the cracking is attributed to the presence of high residual stresses resulting from extensive repairs of the subject weld. The staff requests the applicant to identify the locations in the McGuire and Catawba RCS piping that contain welds fabricated from Alloy 82/182 material. Additionally, the staff requests the applicant to describe the actions it plans to take to address this operating experience as it applies to McGuire and Catawba. This issue is characterized as open item 3.0.3.10.2-2.

For bolting, in addition to the aging management programs listed, the applicant stated that information from operating experience indicates that there are additional elements of bolting maintenance procedures that should be considered, such as personnel training, installation and maintenance procedures, plant-specific bolting degradation history, and corrective measures. The NRC captured the lessons from this experience in Bulletin 82-02, which was issued June 2, 1982, and directed each licensee to assure that these lessons were being incorporated at their plant. In its response to Bulletin 82-02, provided by letters dated August 2, 1982, and July 19, 1984, the applicant submitted the results of the in-house investigation and provided assurance that bolting maintenance practices did indeed consider these lessons learned. In summary, the applicant stated that routine maintenance practices have included use of properly trained personnel and procedural guidance to construct bolted closures. The continuation of routine maintenance practices reviewed under Bulletin 82-02 will assure aging management of mechanical closure integrity for bolted closures in the reactor coolant system.

The staff has reviewed the applicant's operating experience with the ISI Plan, as well as the information submitted in response to Bulletin 82-02. The staff considers the operating experience to be a reasonable basis on which to conclude that the ISI Plan has been effective at maintaining the intended function of the components included in the program and can reasonably be expected to do so for the period of extended operation.

3.0.3.10.3 FSAR Supplement

The FSAR Supplement for McGuire, provided in Appendix A-1, Section 18.2.16, of the LRA, contains a description of the McGuire 1 cold leg elbow inspection program and the small bore piping inspection program. The FSAR Supplement for Catawba, provided in Appendix A-2, Section 18.2.15, of the LRA, contains a description of the small bore piping inspection program. These program descriptions are consistent with the discussion provided in Appendix B of the LRA. However, pending resolution of open items 3.0.3.10.2-1 and 3.0.3.10.2-2, revisions to the FSAR supplement may be warranted to reflect volumetric examination of small-bore piping.

3.0.3.10.4 Conclusions

The staff has reviewed the information provided in Section B.3.18 of the LRA, and the summary description in the FSAR Supplement in Appendix A of the LRA. On the basis of this review and the above evaluation, with the exception of open items 3.0.3.10.2-1 and 3.0.3.10.2-2, the staff finds that there is reasonable assurance that the effect of aging associated with the Class 1 pressure retaining components and Class 2 pressure boundary portions of the steam generators will be adequately managed such that the intended function will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.11 Inspection Program for Civil Engineering Structures and Components

The applicant described its Inspection Program for Civil Engineering Structures and Components for McGuire and Catawba in Section B.3.21 of the LRA. The LRA credits this inspection program with assessing the ongoing, overall condition of the buildings and structures, and with identifying any ongoing degradation, through a visual inspection process. The program monitors and assesses the condition of structures affected by aging, which may cause loss of material, cracking, and change of material properties. The staff reviewed the application to determine whether the applicant has demonstrated that the program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.11.1 Technical Information in the Application

Section B.3.21 of the LRA describes the Inspection Program for Civil Engineering Structures and Components as an existing aging management program that provides for periodic visual inspections to monitor the condition of structures and the exposed external surfaces of mechanical components within the structures. The monitored structures for McGuire are:

- Auxiliary building structures (including the control building, diesel generator buildings, fuel buildings, main steam doghouses)
- Reactor buildings (including internal structures and station vents)
- Standby nuclear service water intake/discharge strictures
- Standby shutdown facility
- Condenser cooling water intake structure (fire pump rooms only)
- Turbine building (including service building)
- Yard structures (including refueling water storage tank and reactor make-up water storage tank foundations, refueling water storage tank missile wall, and trenches)

The monitored structures for Catawba are:

- Auxiliary building structures (including the control complex, diesel generator buildings, doghouses, fuel buildings, fuel pools)
- Nuclear service water (NSW) and standby nuclear service water (SNSW) structures (including NSW and SNSW pump structure, NSW intake structure, SNSW discharge structures, SNSW intake structure, and SNSW pond outlet)
- Reactor buildings (including station vent, internal reactor building structures, and containment recirculation sump screen assembly)
- Standby shutdown facility
- Turbine building (including service building)
- Yard structures (including low pressure service water intake structure, refueling water storage tank foundation and missile shield, yard drainage system, and trenches).

The Inspection Program for Civil Engineering Structures and Components is a condition monitoring program credited with managing the following aging effects for the period of extended operation:

- Loss of material due to corrosion for exposed surfaces of steel components: anchorage/embedments; cable tray and conduit supports; checkered plates; equipment component supports; expansion anchors; flood curbs, flood, pressure, and specialty doors; HVAC duct supports; instrument line supports; instrument racks and frames; lead shielding supports; metal roof (McGuire only), metal siding; pipe supports; stair, platform, and grating supports; structural steel beams, columns, plates and trusses; sump screens; and the unit vent stack

- Cracking of masonry block walls
- Change in material properties due to leaching of concrete walls and roofs
- Loss of material and cracking for reinforced concrete beams, columns, and walls for the nuclear service water structures and low pressure service water intake structure (Catawba only)
- Cracking and change in material properties of elastomeric flood seals (Catawba only)
- Loss of material of composite roofing
- Loss of material of exposed external surfaces of mechanical components
- Loss of material of the steel components of the yard drainage system (Catawba only)

The LRA states that the Inspection Program for Civil Engineering Structures and Components is applicable in meeting the regulatory requirements of 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.”

3.0.3.11.2 Staff Evaluation

The staff’s evaluation of the Inspection Program for Civil Engineering Structures and Components focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures. The staff’s evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] The staff finds that the structures and components monitored by the Inspection Program for Civil Engineering Structures and Components, as listed in Section B.3.21 of the LRA, cover the scope of license renewal as identified in Section 2.4 of the LRA. The staff finds that the scope of the program is acceptable since it includes a walkdown inspection of all structures and components within the scope of license renewal.

[Preventive and Mitigative Actions] There are no preventive or mitigative actions taken as part of this program, and the staff did not identify the need for such actions.

[Parameters Inspected or Monitored] The Inspection Program for Civil Engineering Structures and Components inspects the structures and the exposed external surfaces of mechanical components within them for the following:

- Concrete: spalling, cracking, delaminations, honeycombs, water in- leakage, chemical leaching, peeling paint, or discoloration
- Masonry walls: significant cracks in joints, unsealed penetrations, missing or broken blocks, or separation from supports

• Structural steel: corrosion, peeling paint, beam/column deflection, loose or missing anchors/fasteners, missing or degraded grout under base plates, twisted beams, and cracked welds
• Equipment foundations: settlement, cracked concrete
• Equipment supports: cracked concrete, loose connections, corroded steel
• Cable tray supports: loose connections, corrosion, distortion, and excessive deflection
• Roof systems: structural integrity, deteriorated penetrations (i.e., drains, vents, etc.), signs of water infiltration, cracks, ponding and flashing degradation
• Seismic gaps: presence of gaps
• Siding: structural integrity and visible damage
• Windows/doors: missing panes, cracks, deteriorated glazing, broken or cracked frames, missing or damaged hardware, and seal integrity
• Trenches: cracks, mis-alignment or damage of covers, may spot check trenches by removing covers and inspecting walls and bottoms for cracks
• Earthen structures/dams: erosion, settlement, slope stability, seepage, drainage systems, integrity of rip-rap, and environmental conditions
• Mechanical components: loss of material for exposed external surfaces (program will be enhanced to add this)
•Yard drainage system: loss of material of steel components (program will be enhanced to add this for Catawba only)

The staff finds the above parameters, such as cracking and spalling of concrete and corrosion of steel, acceptable because they are directly related to the degradation of civil structures and components, and visual inspections are effective and adequate to detect such conditions.

[Detection of Aging Effects] The aging effects that are managed by the Inspection Program for Civil Engineering Structures and Components monitoring program are identified through visual inspections. The LRA states that each structure or component is inspected from the interior and exterior where accessible. Whenever normally inaccessible areas are made accessible (i.e., by excavation or other means), an inspection is performed and the results are documented as part of the program. The LRA also states that inspections are performed by a team of at least two people. Inspectors are qualified by appropriate training and experience and approved by responsible plant management.

By letter dated January 28, 2002, the staff asked, in RAI B.3.21-1, the applicant to describe the qualification and required experience of the inspector. In its response dated March 11, 2002, the applicant stated that the qualifications of the inspector are documented in McGuire and Catawba site documents. The applicant stated that the inspectors should be civil/structural engineering graduates with at least 4 years experience in evaluation of inservice structures. The staff finds that degreed civil/structural engineers with at least 4 years experience in evaluating inservice structures are adequately qualified and sufficiently experienced.

[Monitoring and Trending] With respect to an inspection frequency, the application states that the Inspection Program for Civil Engineering Structures and Components is nominally performed every five years with the exact schedule being established with consideration of refueling outages for each unit, and the interval may be increased to a nominal ten-year frequency with appropriate justification based on the structure, environment, and related inspection results. The applicant's operating experience to date supports the continuation of a five-year frequency for inspections. Furthermore, the staff finds that the five-year frequency is consistent with industry experience and is, therefore, acceptable. The staff finds that the monitoring and trending activities described by the applicant are adequate to ensure that corrective actions will be taken prior to exceeding the acceptance criteria.

[Acceptance Criteria] The LRA states that the acceptance criteria are no unacceptable visual indications of loss of material, cracking or change of material properties for concrete, and loss of material for steel, as identified by the accountable engineer. Acceptable structures or components are those which are capable of performing their intended function(s) until the next scheduled inspection and are considered to meet the requirements contained in 10 CFR 50.65(a)(2). Unacceptable structures or components are those that are either (1) damaged or degraded such that they are not capable of performing their intended function, or (2) degraded to the extent that, if uncorrected before the next normally scheduled inspection, the structure or component might not perform its intended function.

In its March 11, 2002, response to RAI B.3.21-1, the applicant stated that the qualifications of the inspector are documented in McGuire and Catawba site documents. The applicant stated that the inspectors should be civil/structural engineering graduates and registered professional engineers with at least 4 years experience in evaluation of inservice structures. The applicant further stated that the qualifications of the inspector are documented in McGuire and Catawba site documents and that the oversight of the training and qualification of the accountable engineer is governed by the Duke Quality Assurance Topical Report. The staff finds that degreed civil/structural engineers with at least 4 years experience in evaluating inservice structures are adequately qualified and sufficiently experienced.

By letter dated January 28, 2002, the staff requested, in RAI B.3.21-2, the applicant to describe the criteria for (1) assessing the severity of the observed degradations; and (2) determining whether corrective actions is necessary. In its response dated March 11, 2002, the applicant stated that the acceptability of a structure is based on whether the accountable engineer determines that the structure is capable of performing its intended function(s) and that the accountable engineer will assess the severity of the degradation and determines whether corrective action is necessary. The applicant also stated that the NRC Regulatory Guide 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” described the acceptability for structural condition monitoring and capability of performing the intended function(s). The applicant further stated that the accountable engineer will use guidance provided in codes and standards, such as NEI 96-03, “Industry Guideline for Monitoring Structures,” NRC Regulatory Guide 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants,” and ACI 349.3, “Evaluation of Existing Nuclear Safety-Related Concrete Structures,” to examine and assess the condition of a structure. The staff considers the applicant’s response acceptable.

The staff finds that the acceptance criteria specified above are adequate to ensure that the structure and component intended function(s) are maintained under all CLB design conditions during the period of extended operation.

[Operating Experience] The LRA states that previous inspections for McGuire noted several minor degraded conditions; however, the conditions did not adversely affect the ability of the structures or components to perform their intended functions. All findings have been addressed by the corrective action program or by station work requests. Items that were noted that required additional investigation, repair or other corrective actions included: missing grout under base plates; degraded coatings on steel, concrete, and pipe supports; minor corrosion of steel; deterioration of expansion joints; and minor cracking and spalling of concrete. Corrective actions included repair or replacement of the affected structure or structural component.

The application states that previous inspections for Catawba revealed no serious degradation or condition that would adversely affect the ability of the structures or components to perform their intended functions. Items that required additional investigation, repair or other corrective actions included: missing grout under base plates; degraded coatings on steel, concrete, and block walls; minor corrosion of steel; deformed metal trench covers; and hairline cracking and leaching of concrete. Corrective actions included repair or replacement of the affected structure or structural component.

The staff finds that the applicant's operating experience indicates that the structural monitoring program has effectively maintained the integrity of the structures and components and that the effects of aging will be adequately managed during the period of extended operation.

3.0.3.11.3 FSAR Supplement

The staff reviewed the FSAR Supplements in Section 18.2.17 of Appendix A.1 and Section 18.2.16 of Appendix A.2, of the LRA for McGuire and Catawba, respectively, and found that the description of the Inspection Program for Civil Engineering Structures and Components is consistent with Section B.3.21 of the LRA. However, the FSAR Supplements do not include reference to several of the important industry codes and standards discussed in the applicant's March 11, 2002, response to the staff's RAI. The applicant is requested to update the FSAR Supplement to incorporate those standards and guidelines. This issue is characterized as open item 3.0.3.11.3-1.

3.0.3.11.4 Conclusions

The staff reviewed Section B.3.21 of the LRA, the summary description in Appendix A of the LRA, and the applicant's March 11, 2002, response to the staff's RAIs. On the basis of this review and the above evaluation, the staff concludes that the applicant has demonstrated that the aging effects managed by the Inspection Program for Civil Engineering Structures and Components will be adequately managed so that there is reasonable assurance that the structures and components covered by this inspection program will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.12 Liquid Waste System Inspection

The applicant described its Liquid Waste System Inspection program in Section B.3.22 of the LRA. The applicant credits this program with managing the potential aging of liquid waste systems structures and components that are within the scope of license renewal. The inspection activity monitors for loss of material and cracking. The staff reviewed Section B.3.22 of the LRA to determine whether the applicant has demonstrated that the liquid waste system inspection activities will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.12.1 Technical Information in the Application

Section B.3.22 of the LRA states that the purpose of the Liquid Waste System Inspection program is to provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of equipment and components within the scope of 10 CFR Part 54 will be maintained consistent with the CLB for the period of extended operation. This program is credited with managing any loss of material and cracking of system components within the scope of license renewal that are exposed to unmonitored borated, treated, and/or raw water environments. The program is credited with managing the potential aging of the following systems:

- Component cooling system (McGuire only) - stainless steel waste evaporator package exposed to an unmonitored treated water environment of the liquid waste recycle system;
- Liquid waste recycle system (McGuire only) - stainless steel components exposed to an unmonitored borated water environment;
- Liquid radwaste system (Catawba only) - stainless steel components exposed to an unmonitored borated water, unmonitored treated water, or a raw water environment; carbon steel and cast iron components exposed to a raw water environment.

The Liquid Waste System Inspection detects aging effects through a combination of volumetric and/or visual examination. For the McGuire component cooling system, one of the four heat exchangers associated with the waste evaporator will be inspected. For the McGuire liquid waste recycle system and the Catawba liquid radwaste system, a combination of volumetric and visual examination will be performed for sample population of components chosen based on conditions likely to cause a more corrosive environment. This is a one-time inspection activity. If evaluation of the inspection findings indicates that continuation of the aging effects will cause a loss of intended function(s), additional inspection will be performed and/or corrective action will be taken.

The applicant concluded that implementation of this program will adequately verify that the components will continue to perform their intended function(s) for the period of extended operation.

3.0.3.12.2 Staff Evaluation

The staff's evaluation of the Liquid Waste System Inspection program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] Section B.3.22 of the LRA identifies the structures and components that credit the liquid waste system inspection activities for managing the aging effects of loss of material and cracking as follows:

- Component cooling system (McGuire only) - stainless steel waste evaporator package exposed to an unmonitored treated water environment of the liquid waste recycle system;
- Liquid waste recycle system (McGuire only) - stainless steel components exposed to an unmonitored borated water environment;
- Liquid radwaste system (Catawba only) - stainless steel components exposed to an unmonitored borated water, unmonitored treated water, or a raw water environment; carbon steel and cast iron components exposed to a raw water environment.

The scope covers the in-scope structures and components that are exposed to the liquid waste system environments; therefore, this is acceptable to the staff.

[Preventative Actions] There are no preventative actions taken as part of this program, and the staff did not identify the need for any preventative actions.

[Parameters Monitored or Inspected] Section B.3.22 of the LRA identifies loss of material and cracking as the parameters that can be detected by volumetric inspection of stainless steel components in the component cooling system (McGuire only), liquid waste recycle system (McGuire only), and the liquid radwaste system (Catawba only). As an alternative, visual examination will be used should access to internal surfaces become available. Because these inspection techniques can be used to identify the degraded conditions noted by the applicant, they are acceptable to the staff.

[Detection of Aging Effects] Section B.3.22 of the LRA states that volumetric and/or visual inspection will detect loss of material and cracking for the structures and components. The use of volumetric and/or visual inspection is considered by the staff to be a reasonable means of detecting these aging effects before the loss of intended function, and is consistent with NRC and industry guidance. Therefore, the staff finds this acceptable.

[Monitoring and Trending] Section B.3.22 of the LRA states that the one-time inspections will be performed as follows:

- for the McGuire component cooling system, one of the four heat exchangers associated with the waste evaporator will be inspected; and
- for the McGuire liquid waste recycle system and the Catawba liquid radwaste system, a combination of volumetric and visual examination will be performed for sample population of components chosen based on conditions likely to cause a more corrosive environment.

By letter dated January 28, 2002, the staff requested, in RAI B.3.22-1, additional information related to the criteria that will be used to select the areas that are inspected. In its response dated March 15, 2002, the applicant stated that the selection criteria will include such items as component orientation, operating temperature, proximity to hot equipment, and previous operating experience. The staff finds the applicant's response reasonable and acceptable.

Section B.3.22 of the LRA states that no actions are taken as part of the program to trend the inspection results. If evaluation of the inspection findings indicates that continuation of the aging effects will cause a loss of intended function(s), additional inspection will be performed and/or corrective action will be taken. Since corrective actions and confirmatory actions, as needed, are implemented in accordance with the corrective action program, the staff finds this acceptable.

[Acceptance Criteria] Section B.3.22 of the LRA states that the acceptance criteria for the inspection is no unacceptable loss of material that could result in the loss of the component intended function(s), as determined by engineering evaluation. By letter dated January 28, 2002, the staff requested, in RAI B.3.22-2, the applicant to describe the criteria for assessing the severity of observed degradations and the need for corrective actions. In its response dated March 15, 2002, the applicant stated that the criteria would be developed at the time of the inspection. Criteria such as the ASME Code, results from additional inspections, and operating experience may be used to assess the severity of the degradation and the need for corrective action. Since the applicant indicated that criteria will be based on ASME Code requirements, results from additional inspections, and operating experience, the staff finds the applicant's response reasonable and acceptable.

[Operating Experience] Section B.3.22 of the LRA states that the Liquid Waste System Inspection is a one-time inspection for which there is no operating experience. The staff finds this reasonable and acceptable.

3.0.3.12.3 FSAR Supplement

The staff reviewed Appendix A of the LRA, Section 18.2.18 the FSAR Supplement for McGuire, and Section 18.2.17 of the UFSAR for Catawba. The staff finds that the summary description is consistent with the LRA and is acceptable.

3.0.3.12.4 Conclusions

The staff has reviewed the information provided in Section B.3.22 of the LRA, the summary description of the Liquid Waste System Inspection in Appendix A of the LRA, and the applicant's March 15, 2002, response to the staff's RAIs. On the basis of this review and the above evaluation, the staff finds that the Liquid Waste Systems Inspection will adequately manage the aging effects such that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.13 Preventative Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection

The applicant described its Preventative Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection program in Section B.3.24.1 of the LRA. The applicant credits this program to manage aging effects of loss of material and cracking that could lead to loss of pressure boundary function for the following systems: condenser circulating water system, diesel generator fuel oil system, fire protection system (internal and external), nuclear service water system, standby shutdown diesel system. The activities are intended to manage loss of material and cracking of internal and external surfaces by maintaining the integrity of the coatings. The staff reviewed Section B.3.24.1 of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.13.1 Technical Information in the Application

In Section B.3.24.1 of the LRA, the applicant has described the activities associated with the Preventative Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection program. The program is credited for the following two purposes for license renewal:

(1) Management of the loss of material of the internal surfaces of the large diameter intake and discharge piping in the condenser circulating water system. The internal carbon steel surfaces of the large diameter intake and discharge piping in the condenser circulating water system are coated to prevent the raw water environment from contacting the internal surfaces. Continued presence of an intact coating precludes loss of material of the internal surfaces of the carbon steel intake and discharge piping. This program will periodically check the condition of the coating and look for coating degradation.

(2) Management of the loss of material and cracking of the external surfaces of components in the underground environment by providing symptomatic evidence of the condition of the piping external surfaces. The external surfaces are coated with a coal tar epoxy that prevents the underground environment from contacting the external surfaces. Continued presence of an intact coating precludes loss of material and cracking of components whose external surfaces are exposed to the underground environment. Inspection of the internal surfaces will provide symptomatic evidence of the condition of the external surfaces of buried components. This inspection is described by the applicant as a condition monitoring program.

The program is applicable to the internal surface of the intake and discharge piping of the condenser circulating water system. The program is also applicable to components exposed to the underground environments in the following McGuire and Catawba systems:

- Diesel generator fuel oil system
- Exterior fire protection
- Interior fire protection (Catawba only)
- Nuclear service water system
- Standby shutdown diesel system

3.0.3.13.2 Staff Evaluation

The staff's evaluation of the Preventative Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures and work processes. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] The applicant defines the scope of the Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection program as the internal surface of the intake and discharge piping of the condenser circulating water system. The program is also applicable to components exposed to the underground environments in the following McGuire and Catawba systems:

- Diesel generator fuel oil system
- Exterior fire protection
- Interior fire protection (Catawba only)
- Nuclear service water system
- Standby shutdown diesel system

During its review of the program, the staff noted that the various elements of the aging management program addressed only the condenser piping with no reference to the other systems listed as being within the program scope. By letter dated January 28, 2002, the applicant was requested, in RAI B.3.24-1, to describe program implementation and operating experience for the other systems within the scope of the program, which may consist of smaller diameter piping. In its response dated March 15, 2002, the applicant stated that, during plant construction, all buried components were coated, wrapped, and backfilled in a consistent manner specified by engineering. The applicant further stated that inspection of the circulating water piping results in approximately 80% of the total buried surface area being inspected by this program. The results of the inspections will be applied to the remaining 20% of surface area residing in the other systems included in the program scope. The staff finds the applicant’s program ineffective at revealing degradation of the external pipe surface before the component pressure boundary is breached and leakage occurs. The staff believes that the applicant should propose an activity to verify that the external surfaces of buried components are not degrading based upon some sampling assessment of most vulnerable locations. This issue is characterized as open item 3.0.3.13.2-1.

[Preventive or Mitigative Actions] The applicant indicated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff considers the inspections to be a means of detecting, not preventing, aging and agrees that there are no preventive actions required.

[Parameters Monitored or Inspected] The applicant stated that the parameters inspected include the internal coatings of the condenser circulating water system piping for chipping, peeling, blistering, and missing coating, as well as signs of corrosion of the underlying carbon steel. By letter dated January 28, 2002, the staff requested, in RAI B.3.24-2, the applicant to discuss what special measures will be applied to facilitate coating inspection for any areas of pipes which may be obscured by deposits, and to describe the criteria for assessing the severity of observed degradations and determining when corrective action is necessary. In its response dated March 15, 2002, the applicant stated that the areas inspected by this activity are normally in service during plant operation and as a result, debris or sediment on the bottom of the pipe has not been observed. The applicant stated that any debris and sediment that obscures the coating will be removed prior to inspection.

Because visual inspection can detect damage to protective coatings and also provide symptomatic evidence of damage to external coating, the staff finds the parameters are appropriate and capable of identifying the effects of aging degradation.

[Detection of Aging Effects] The applicant stated that the program will visually inspect the internal coatings of the intake and discharge piping for chipping, peeling, blistering, and missing coating, as well as signs of corrosion of the underlying carbon steel. The staff disagrees with the applicant and considers inspection of the internal pipe surfaces to be inadequate for monitoring degradation of the external surfaces of buried components (piping and tanks) so that corrective action can be taken before a failure (pitting and leakage) occurs. This issue is characterized as open item 3.0.3.13.2-1.

[Monitoring and Trending] The applicant stated that the program will visually inspect the internal coatings of the intake and discharge piping every five years for coating degradation. Although the external surfaces of the piping are not accessible, externally generated through-wall pits will be revealed through the observance of blistering, peeling, or missing coatings as well as signs of corrosion of the underlying pipe and inleakage of soil or groundwater. The applicant stated that no actions are taken as part of this activity to trend inspection results.

Based on the staff's review of the application and responses to the staff's RAIs, the staff disagrees with the applicant and considers inspection of the internal pipe surfaces to be inadequate for monitoring degradation of the external surfaces of buried components (piping and tanks) so that corrective action can be taken before a failure (pitting and leakage) occurs. This issue is characterized as open item 3.0.3.13.2-1.

[Acceptance Criteria] The applicant described the acceptance criteria as "no visual indications of coating defects" that have led to corrosion of the underlying carbon steel surfaces as determined by engineering evaluation. By letter dated January 28, 2002, the staff requested, in RAI B.3.24-3, the applicant to better describe the criteria to be applied. In its response dated March 15, 2002, the applicant indicated that if the inspections identify indications of coating defects, the conditions will be evaluated using the corrective action process. Criteria such as wall loss of the underlying metal, service life of the coating, root-cause analysis of the coating failure, and operating experience could be used to assess the severity of the degradations and the need for corrective actions. The staff finds the response to be acceptable and agrees that because the visual inspections are capable of detecting degradation of component surfaces and the approach is consistent with industry practices, the acceptance criteria are acceptable to the staff.

[Operating Experience] The applicant stated that one complete inspection has been performed on the McGuire intake and discharge piping, including the low-level intake piping from Cowans Ford Dam through the low-level intake structure to the main intake, within the last 5 years. The applicant reported that the internal coating was observed to be in good condition with random minor defects and corrosion. The applicant reported that the condenser circulating water system intake and discharge piping has experienced two leaks, one a crack in a weld near the low-level intake pumps, which the applicant identified as being due to one or two water hammer events. The applicant also found a pinhole during a visual inspection of the low-level intake piping. The applicant reported that the diameter of the pinhole was larger on the outside diameter than the inside diameter, indicating that the corrosion initiated on the external surface of the pipe. The applicant repaired the pinhole with a steel pipe plug and did not inspect the external surface of the pipe.

At Catawba, the applicant enters the condenser circulating water system every outage for blasting and recoating and/or a walkdown of areas that are not recoated. The applicant is performing this work because the original interior coating was not properly applied and is failing. In performing these recoating and walkdown inspections, the applicant has not identified any through-wall pits originating from the exterior of the pipe. Upon completion of the recoating work, it is the applicant's stated intent that Catawba will go to a five-year inspection frequency.

During the Catawba 1 outage in the fall of 2000, the applicant cleaned piping in the nuclear service water system to remove the fouling buildup from the pipe walls. Internal inspection of accessible areas after the cleaning discovered a row of small through-wall pits. The applicant excavated the pipe and an examination of the external coating revealed that the coating had been cut during construction, allowing the underground environment to contact the external surface. Except for the cut, the applicant noted that the external coating was in good shape. The applicant has also identified other instances of externally generated through-wall leaks of buried components that have been attributed to construction-related damage.

The staff finds that the applicant's operating experience with the Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection indicates that the activities are effective in managing loss of material of the piping and tanks by maintaining the effectiveness of the internal coatings. In the case of the buried piping, the staff finds the applicant's program ineffective at revealing degradation of the external pipe surface before the component pressure boundary is breached and leakage occurs. The staff believes that the applicant should propose an activity to verify that the external surfaces of buried components are not degrading based upon some sampling assessment of most vulnerable locations. This issue is characterized as open item 3.0.3.13.2-1.

3.0.3.13.3 FSAR Supplement

Appendix A-1, Section 18.2.20, and Appendix A-2, Section 18.2.19, of the LRA contains proposed new UFSAR sections for McGuire and Catawba, respectively. The staff reviewed this material and finds it to be consistent with the material provided in Appendix B; however, a revision to the FSAR supplement summary description of this AMP may be necessary to reflect any changes made to the program in a effort to resolve open item 3.0.3.13.2-1. Therefore, the staff's determination about the acceptability of the FSAR supplement is contingent upon the resolution of the open item. This issue is characterized as open item 3.0.3.13.2-1.

3.0.3.13.4 Conclusion

The staff reviewed the information provided in Section B.3.24.1 of the LRA, the summary description in the FSAR Supplement in Appendix A of the LRA, and the applicant's March 15, 2002, responses to the staff's RAIs. On the basis of this review and the above evaluation, with the exception of open item 3.0.3.13.2-1, the staff finds that there is reasonable assurance that the aging effect of loss of material of the internal carbon steel piping and components within the scope of the program will be adequately managed such that the intended function will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.14 Selective Leaching Inspection Program

The applicant described its AMR of the selective leaching inspection program in Section B.3.28 of Appendix B of the LRA. This program aims to verify the integrity of components made of brass and cast iron that are exposed to raw water environments that may cause selective leaching of these components such that they may lose their pressure boundary function in the period of extended operation. The staff reviewed the application to determine whether the applicant has demonstrated that the selective leaching inspection program will adequately manage the applicable effects of aging in the plant during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.14.1 Technical Information in the Application

In Section B.3.28 of the LRA, the applicant describes a new program that will be implemented to determine the acceptability of the brass and cast iron components exposed to selective leaching in raw water environments. These types of environments exist in the McGuire and Catawba Nuclear Stations and affect brass and cast iron components in the following systems:

- conventional wastewater treatment (McGuire only)
- diesel generator room sump pump (McGuire only)
- exterior fire protection
- groundwater drainage (McGuire only)
- interior fire protection
- nuclear service water (McGuire only)

The proposed selective leaching inspection program will provide a one-time inspection of the affected components. It will consist of inspecting a select set of cast iron pump casings to determine whether loss of material due to selective leaching is occurring and whether it will cause concern for the period of extended operation. The applicant stated that Brinnell hardness checks will be used to determine if the phenomenon is occurring, and if it is, an engineering evaluation will be initiated to determine the acceptability of the affected components for further service. The selective leaching inspection also includes the performance of a Brinnell hardness test or an equivalent test on a sample of brass valves in the interior fire protection system at each site.

3.0.3.14.2 Staff Evaluation

The staff's evaluation of the selective leaching inspection program focused on how the program managed aging effects through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program. The staff's evaluation of the applicant's quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] The applicant stated that uncertainty exists as to whether long term exposure to raw water environments could cause loss of material due to selective leaching in brass and cast iron components such that they may lose their pressure boundary function in the period of extended operation. Therefore, the purpose of the Selective Leaching Inspection is to characterize loss of material (if any occurs) due to selective leaching of system components exposed to raw water environments. The applicant indicated that the scope of the selective leaching inspection program includes brass and cast iron components exposed to raw water in the systems listed above. The staff found the program scope to be acceptable because the information in the application is comprehensive and includes the systems and structures that are subject to the applicable aging effects of selective leaching.

[Preventive or Mitigative Actions] The applicant indicated that no actions are taken as part of this program to prevent or mitigate aging degradation. The staff considers inspection activities to be a means of detecting, not preventing, aging and therefore, agrees that there are no preventive actions required.

[Parameters Monitored or Inspected] The applicant stated that the parameter inspected by the selective leaching inspection is the hardness of the wetted surface of cast iron pump casings and brass valve bodies. The applicant described selective leaching as the dissolution of one metal in an alloy at the metal surface, which leaves a weakened network of corrosion products that is revealed by a Brinnell hardness check or equivalent test as a reduction in material hardness. By letter dated January 28, 2002, the staff asked, in RAI B.3.28-1, the applicant to provide the basis for concluding that the inspection of a single pump casing and a brass valve body in the exterior fire protection system at each site will be indicative of the state of selective leaching in all cast iron and brass components in all raw water systems. Also, in RAI B.3.28-2, the applicant was asked to describe the analyses or evaluations that will be used to determine the sample size for the valve inspections.

In its response dated March 15, 2002, the applicant stated that specific material types of gray cast iron and yellow brass are susceptible to loss of material due to selective leaching. The applicant was unable to confirm, from vendor documents, that the selected components were not constructed of gray cast iron. Since the aging effect could not be absolutely ruled out, the applicant considered the inspection to be warranted. The applicant stated that it believed that the environment in the exterior fire protection system pump casings is the most aggressive for promoting selective leaching and bounds the environments of the other pump casings and is equivalent to the environment of the valve bodies. The applicant stated that due to the small number of components involved and the likelihood that the components are not constructed of gray cast iron, the applicant believed that inspection of one pump casing at each site bounds the other components.

With regard to valves, the applicant stated that the total number of brass valves exposed to raw water will be determined prior to the inspection. A subset for inspection will be determined by focusing on those valves exposed to low flow or stagnant conditions. This subset may be further narrowed by component geometry/location, component operating experience, length of service, accessibility, and radiological concerns. The information in the application and the responses adequately addressed the staff’s concerns. The staff concludes that the inspection of a single pump and the valve sample size will be representative of selective leaching in other raw water systems. The staff found that the inspections will be capable of detecting the effects of leaching, the inspection methods are consistent with current industry practice and will allow the applicant to take corrective action prior to loss of component function; therefore, the staff found the parameters inspected/monitored acceptable.

[Detection of Aging Effects] The applicant described this activity as a one-time inspection that will detect the presence and extent of any loss of material due to selective leaching. The staff found, based on the material in the application that the inspection will be capable of detecting aging effects and will permit the applicant to take corrective actions prior to loss of component intended function.

[Monitoring and Trending] The applicant stated that of the cast iron components in the systems within the scope of the program, the selective leaching inspection will perform a Brinnell hardness test or an equivalent test on one cast iron pump casing in the exterior fire protection system at each site. The Brinnell hardness test or an equivalent test is most easily performed on a pump casing and will be indicative of all cast iron components in the systems listed above.

According to the application, the exterior fire protection system contains a raw water environment that is susceptible to selective leaching and will be bounding for the other environments in the other systems. If no parameters are known that would distinguish among the pump casings, the applicant stated that one of the three cast iron pump casings in the exterior fire protection system will be examined based on accessibility and operational concerns. The results of this inspection will be applied by the applicant to the other cast iron components exposed to raw water environments in the systems listed above. The selective leaching inspection program will also perform a Brinnell hardness test or an equivalent test on a sample of brass valves at each site in the interior fire protection system. Valves selected for inspection will be in locations where they are continuously exposed to stagnant or low flow raw water environments. If no parameters are known that would distinguish the susceptible locations at each site, a select set of susceptible locations will be examined by the applicant based on accessibility, operational, and radiological concerns. The results of the inspection will be applied to brass components exposed to raw water environments in the systems listed above.

Based on the information in the application, the staff found that the monitoring and trending activities will provide a basis on which the applicant may make a determination of acceptability of the components in the systems subject to the aging management program.

[Acceptance Criteria] The acceptance criteria for the selective leaching inspection is no unacceptable loss of material due to selective leaching that could result in a loss of the component intended functions(s) as determined by engineering evaluation. By letter dated January 28, 2002, the staff requested, in RAI B.3.28-3, that the applicant describe the criteria to be used to define “unacceptable loss of material” and to describe the analysis methodology that will be used to evaluate the inspection results against the acceptance criteria.

In its response dated March 15, 2002, the applicant stated that if evidence of loss of material is observed during the initial inspection, a problem report will be developed in accordance with “Problem Investigation Process of Nuclear System Directive 208.” The problem investigation process is a formalized process used by the applicant for documenting engineering evaluations of plant problems. The applicant provided examples of criteria or analysis methods that may be used, including ASME Code requirements, to assess the severity of degradation and need for corrective action. The applicant stated that any criteria or analysis methods involved in determining the severity of the degradation and the need for corrective action will be developed at the time of the evaluation and will be a part of the problem report. The staff finds that, because degradation is detectable by the methods to be applied; ASME Code requirements or some other analysis method will be applied as acceptance criteria; and the existing problem investigation process conforms to 10 CFR Part 50, Appendix B requirements (as documented in Section 3.0.4 of this SER), the acceptance criterion is acceptable.

[Operating Experience] This program is described by the applicant as a new, one-time inspection for which there is no operating experience. Since there is no operating experience with this new AMP, and since uncertainty exists as to whether long term exposure to raw water environments could cause loss of material due to selective leaching in brass and cast iron components such that they may lose their pressure boundary function in the period of extended operation, the staff finds this one-time inspection an acceptable means to characterize any loss of material due to selective leaching of system components exposed to raw water environments.

With respect to the inspection timing, the applicant stated that this one-time inspection will be completed by June 12, 2021, for McGuire and by December 6, 2024, for Catawba.
The staff finds this inspection schedule acceptable. If present, selective leaching is a slow acting corrosion mechanism; thus, the staff expects minimal corrosion, if any, and finds the use of a one-time inspection capable of identifying degradation and will allow the applicant to take appropriate corrective action prior to loss of component function.

3.0.3.14.3 FSAR Supplement

Appendix A-1, Section 18.2.23 contains the McGuire FSAR Supplement describing the selective leaching inspection program. Appendix A-2, Section 18.2.22 contains the Catawba FSAR Supplement for the selective leaching inspection program. The contents of these sections are consistent with the description provided in Appendix B, Section B.3.28, therefore the staff does not see the need for changes.

3.0.3.14.4 Conclusions

The staff has reviewed the information provided in Section B.3.28 of the LRA. On the basis of this review, as set forth above, including the applicant's responses to the staff requests for additional information, the staff found that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the selective leaching inspection program structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.15 Service Water Piping Corrosion Program

The applicant describes the Service Water Piping Corrosion Program at McGuire and Catawba in Section B.3.29 of the LRA. The purpose of the program is to manage aging effects of loss of material due to corrosion or erosion that could lead to loss of the pressure boundary function of specific raw water system components. The staff reviewed Section B.3.29 of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.15.1 Technical Information in the Application

The applicant has described the Service Water Piping Corrosion Program in Section B.3.29 of the LRA. The purpose of this program is to manage the more uniform loss of material, such as that due to general corrosion as well as particulate erosion in areas of higher flow velocity, for the following systems:

- Containment ventilation cooling water (McGuire only)
- Exterior fire protection
- Interior fire protection
- Nuclear service water

Additionally, the program is credited with managing loss of material for heat exchanger sub-components in the following systems:

- Containment spray
- Diesel generator cooling water
- Control area chilled water
- Diesel generator engine starting air (Catawba only)

Components subject to these aging effects are made from carbon and galvanized steel, cast and ductile iron, and copper alloys in the McGuire and Catawba raw water systems.

3.0.3.15.2 Staff Evaluation

The staff's evaluation of the Service Water Piping Corrosion Program focused on how the program elements rather than details of specific plant procedures. The staff evaluated how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures and work processes. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] For license renewal, the applicant credits the Service Water Piping Corrosion Program with managing loss of material for components in the following systems:

- Containment ventilation cooling water (McGuire only)
- Exterior fire protection
- Interior fire protection
- Nuclear service water

Additionally, the program is credited with managing loss of material for heat exchanger sub-components in the following systems:

- Containment spray
- Diesel generator cooling water
- Control area chilled water
- Diesel generator engine starting air (Catawba only)

Because this scope is comprehensive in that it includes those components and systems subject to general corrosion, the staff finds the scope acceptable.

[Preventive or Mitigative Actions] The applicant stated that no actions are taken as part of the program to prevent aging effects or to mitigate aging degradation. The staff considers the inspections as a means to detect, not prevent degradation, and therefore did not identify a need for preventive actions.

[Parameters Monitored or Inspected] The applicant stated that the Service Water Piping Corrosion Program inspections are focused on carbon steel piping components exposed to raw water. Among the installed component materials, carbon steel is the more susceptible to general loss of material and serves as a leading indicator of the general material condition of the system components. The applicant relies on inspection of carbon steel piping to provide symptomatic evidence of loss of material of other components and other materials exposed to raw water. The specific parameter monitored by the applicant is pipe wall thickness as an indicator of loss of material. Because monitoring wall thickness will provide a valid indicator of loss of material and provide an opportunity to take corrective action before loss of component function, and because this is a standard industry practice, the staff finds this acceptable.

[Detection of Aging Effects] The applicant stated that the Service Water Piping Corrosion Program will detect the more uniform loss of material, such as that due to general corrosion as well as particulate erosion that may occur in areas of higher flow velocity. The program will also detect loss of material due to localized corrosion such as crevice, pitting, and microbiologically influenced corrosion (MIC). Because the program uses volumetric techniques current in the industry and capable of detecting aging effects in the inspected components, the staff finds this acceptable.

[Monitoring and Trending] The applicant stated that the Service Water Piping Corrosion Program manages all of the system components within license renewal scope that are susceptible to the various corrosion mechanisms, and is not focused on individual components within each specific system. As described in the LRA, the intent of the program is to inspect a number of locations with conditions that are characteristic of the conditions found throughout the raw water systems within the program scope. The applicant then applies the results of these inspections to similar locations throughout all the raw water systems within the scope of license renewal. This characteristic-based approach recognizes the commonality among the component materials of construction and the environment to which they are exposed.

Monitoring under the program focuses on carbon steel pipe. Industry experience has shown that loss of material for components constructed of cast and ductile iron, galvanized steel and copper alloys will occur at a rate somewhat less than the carbon steel pipe. Therefore, the results of the carbon steel pipe inspections will provide a leading indicator of the condition of these materials.

For the carbon and galvanized steel, cast and ductile iron, and copper alloy component materials that can experience loss of material from both uniform and localized mechanisms, the applicant stated that it is the gross material loss due to uniform mechanisms that is of primary concern under the Service Water Piping Corrosion Program. Gross wall loss can lead to structural instability concerns and could directly impact component intended function. Monitoring for uniform loss of material is accomplished with the use of ultrasonic test techniques, supplemented by visual inspections if access to the interior surfaces is allowed, such as during plant modifications.

When pipe wall thickness is determined by volumetric wall thickness measurements using ultrasonic testing, several measurements are taken around the circumference of the piping. These measurements are then assessed in relation to the specific acceptance criteria for that location. Because the phenomena are slow-acting, inspection frequency varies for each location. The frequency of re-inspection depends on previous inspection results, calculated rate of material loss, piping analysis review, pertinent industry events, and plant operating experience. Component results are catalogued by the applicant, and future inspection or component replacement schedules are determined as a part of the program.

The applicant stated that localized corrosion due to pitting and MIC will reveal itself through pinhole leaks in the piping components. The geometry of the pinholes means that they are not a structural integrity concern. Further, these pinhole leaks cannot individually lead to loss of the component intended function, since sufficient flow at prescribed pressures can still be provided by the system. These localized concerns will lead to structural integrity concerns only when a significant number of pinholes are present. A trend of indications of through-wall leaks due to pitting corrosion or MIC will provide the applicant with evidence when localized corrosion may become a structural integrity concern and will trigger corrective actions. However, the staff believes that localized corrosion can result in the loss of pressure boundary intended function under a design basis event before the corrosion reveals itself as pinhole leaks. Therefore, the applicant should justify how its program will manage the effects of localized corrosion from pitting and MIC to ensure that the intended pressure boundary function can be maintained under all design basis events consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(3). This issue is characterized as open item 3.0.3.15.2-1.

While the emphasis of the Service Water Piping Corrosion Program remains on gross material loss, the loss of material due to localized corrosion of component materials exposed to raw water will be managed by the monitoring and trending of relevant plant operating experience of non-structural, through-wall leaks identified during various plant activities. Methods used by the applicant to identify incidents of through-wall leaks are system walkdowns, operator rounds, system testing, and maintenance activities. This relevant operating experience will form the basis for any future programmatic actions with respect to pitting corrosion and MIC concerns.

By letter dated January 28, 2002, the staff requested, in RAI B.3.29-1, additional information regarding the methods the applicant planned to use to select the ultrasonic testing (UT) procedures and the number of locations to be inspected. In its response dated March 15, 2002, the applicant stated that the methods used to select the ultrasonic testing procedures, including grid size and the number of locations to be inspected, were developed as a department initiative among the applicant's three nuclear plant sites. Original efforts to define inspection procedure details were made as a part of the applicant's response to NRC Generic Letter 89-13. Additionally, the applicant has been involved in industry efforts sponsored through EPRI to address the service water corrosion issue.

The staff finds this response to be acceptable and concludes, based on information in the application and the response to the question, that the monitoring and trending of the inspection results is capable of identifying problems before they could result in loss of pressure boundary integrity.

[Acceptance Criteria] The Service Water Piping Corrosion Program manages loss of material for nuclear safety related and non-nuclear safety related components. For nuclear safety related components designed to ASME Section III, Class 3 rules, the acceptance criteria are defined as meeting ASME Code requirements in order to assure structural integrity. Several factors are used by the applicant to determine structural integrity at an inspection location. These factors include consideration of actual as-found wall thickness, calculated rate of material loss, use of the piping stress analyses to determine a minimum required thickness, and projected time to reach the minimum wall thickness. Projected time to reach the minimum wall thickness will establish the re-inspection interval or component replacement schedule.

For the non-nuclear safety related components that have no seismic design requirements, the applicant's acceptance criterion is the minimum wall thickness calculated on a location-specific basis. These minimum values have been determined by the applicant based on design pressure or structural loading using the piping design code of record and applying additional conservatism.

The staff concludes that, because the inspection methods are capable of detecting the effects of corrosion and the inspections are performed using common industry methods, the acceptance criteria are appropriate for the various classes of components inspected.

[Operating Experience] The Service Water Piping Corrosion Program was formalized by the applicant at each site in the early 1990's as a part of the efforts to address NRC Generic Letter 89-13. Test results have indicated mostly pitting corrosion problems. Typical corrosion rates have ranged from 3 to 5 mils per year average wall loss, but vary depending on line size and flow regime. Test locations continue to be monitored and evaluated by the applicant for continued service. The applicant stated that piping replacements have not been required to date based on corrosion rate projections. The applicant has refined the predictive capabilities of the program over time and the program now includes monitoring and trending to determine calculated rate of material loss to schedule the next inspection. Operating experience has demonstrated that using measured corrosion rates provides adequate information on the extent of loss of material to predict when replacement of components might be necessary. Stress analysis of components has allowed the applicant to refine acceptance criteria and extend the life of some pipe sections. Overall the applicant reports that the program continues to successfully manage loss of material in the raw water systems of McGuire and Catawba.

By letter dated January 28, 2002, the staff requested, in RAI B.3.29-2, additional information and examples regarding the corrosion rates for specific systems, and examples of how measurements have been used to determine frequencies of re-inspection and to expand the number of locations for wall thickness measurements. In its response dated March 15, 2002, the applicant stated that a review of over one hundred inspection locations in the nuclear service water system revealed that the worst locations experience corrosion rates of approximately 3-5 mils per 18-month operating cycle, based on the low band averages (lowest average wall thickness in a circumferential band) of the inspection locations.

The applicant stated that other locations, such as stagnant locations, exhibited much lower corrosion rates. The applicant stated that the frequency of reinspection is determined using the calculated corrosion rate. Corrosion rate, and thus reinspection frequency, is determined by comparing the low-band average of the inspection location against the nominal wall thickness and is averaged against the number of operating cycles. This value is then compared against the minimum allowed wall thickness to determine the remaining life (approximate replacement cycle). The applicant further stated that sample expansion has been rarely required because of the number of inspection locations already in the program. The program provides data points representing all piping, including piping upstream and downstream of major pieces of equipment, every pipe size, different flow regimes and each stress analysis math mode. In its response, the applicant stated that sample expansion is performed in some instances where one inspection location is used as a representative location of both trains or units to include inspection of the opposite train or unit.

Because the applicant adequately addressed the specific information requested, the staff finds the response to be acceptable. Additionally, the staff finds that the applicant's experience is consistent with that of others in the industry and provides a sound basis for successful management of material loss in the raw water systems. Therefore, the staff concludes that the operating experience indicates that the program has been effective, and there is reasonable assurance that it will continue to be effective, at managing the aging effects through the period of extended operation.

3.0.3.15.3 FSAR Supplement

Appendix A-1, Section 18.2.24, and Appendix A-2, Section 18.2.23, of the LRA provide proposed new UFSAR sections describing the Service Water Piping Corrosion Program for McGuire and Catawba, respectively. The staff reviewed the material provided for the UFSAR and found that the information is consistent with the material in the LRA and is, therefore, acceptable.

3.0.3.15.4 Conclusion

The staff reviewed the information provided in Section B.3.29 of the LRA, the summary description in the FSAR Supplement in Appendix A of the LRA, and the applicant's March 15, 2002, responses to the staff's RAIs. On the basis of this review and the above evaluation, with the exception of open item 3.0.3.15.2-1, the staff finds that there is reasonable assurance that the Service Water Piping Corrosion Program will adequately manage the aging effects such that the intended function will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.16 Sump Pump Systems Inspection

The applicant described its Sump Pump Systems Inspection program in Section B.3.32 of the LRA. The applicant credits this program with managing the potential aging of sump structures and components that are within the scope of license renewal. The activity is a one-time volumetric inspection of the structures and components of the limiting sump, the diesel generator room sump, to detect loss of material. The staff reviewed Section B.3.32 of the LRA to determine whether the applicant has demonstrated that sump pump systems inspection activities will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.16.1 Technical Information in the Application

Section B.3.32 of the LRA states that the purpose of the Sump Pump Systems Inspection program is to characterize any loss of material of the internal and external surfaces of a limited set of mechanical components exposed to sump environments. Sump environments may contain leakage from a variety of systems, but are considered to be raw water environments with alternate wetting and drying as sump levels change. Uncertainty exists as to whether long term exposure to these sump environments could cause loss of material of system components such that they may lose their pressure boundary function in the period of extended operation. This activity will inspect components constructed of various materials to detect the presence and extent of any loss of material from exposure to raw water, including alternate wetting and drying. This is a one-time inspection for the following systems:

- Diesel generator room sump pump system
- Conventional waste water treatment system (McGuire only)
- Groundwater drainage system
- Turbine building sump pump system (Catawba only)

3.0.3.16.2 Staff Evaluation

The staff's evaluation of the Sump Pump Systems Inspection program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the plant procedures. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope] The scope of the Sump Pump Systems Inspection is a limited set of mechanical components constructed of carbon steel, cast iron, and stainless steel exposed to sump environments in the following McGuire and Catawba systems:

- Diesel generator room sump pump system
- Conventional waste water treatment system (McGuire only)
- Groundwater drainage system
- Turbine building sump pump system (Catawba only)

The staff finds the scope of the program adequate because it will detect and manage the aging effects in the components subject to sump pump environments.

[Preventive or Mitigative Actions] No actions are taken as part of this program to prevent aging effects or to mitigate aging degradation, and the staff did not identify a need for any.

[Parameters Monitored or Inspected] The parameter inspected by the Sump Pump Systems Inspection is wall thickness as a measure of loss of material. The staff finds that wall thickness measurement will permit detection of aging effects in sump pump components, and is acceptable.

[Detection of Aging Effects] The Sump Pump Systems Inspection is a one-time inspection that will detect the presence and extent of loss of material due to crevice, general, pitting, and microbiologically influenced corrosion. Volumetric inspections will be used to determine wall thickness measurements. The staff finds that the determination of wall thickness by this technique will provide satisfactory means for detecting aging effects in the components exposed to sump pump environments.

[Monitoring and Trending] Section B.3.32 of the LRA describes the sump pump systems inspection activities as follows:

> The “Sump Pump Systems Inspection” will inspect sump components at each site located within the Diesel Generator Room Sump Pump System using a volumetric examination technique. The Diesel Generator Room Sump Pump System was selected for inspection because the system contains a representation of all of the materials present within the other sump environments. The sump environment in the Diesel Generator Room Sump Pump System is a potential combination of leakage of raw water, fuel oil, and treated water. Inspection of the Diesel Generator Room Sump Pump System will provide a representative review of the condition of mechanical components materials subject to a sump environment.
>
> Inspection locations will be at piping low points, pump casings, and valve bodies where materials are continuously wetted by the raw water environment or subject to alternate wetting and drying. The results of this inspection will be applied to the mechanical components in the Conventional Waste Water Treatment (MNS only), Groundwater Drainage, and Turbine Building Sump Pump Systems (CNS only).

Section B.3.32 of the LRA states that no actions will be taken as part of this activity to trend inspection or test results. The staff did not identify the need for any. Section B.3.32 of the LRA also stated that, should industry data or other evaluations indicate that the above inspections can be modified or eliminated, the applicant will provide plant-specific justification to demonstrate the basis for the modification or elimination. The staff finds this acceptable.

[Acceptance Criteria] Section B.3.32 of the LRA states that the acceptance criteria for the inspection is no unacceptable loss of material that could result in the loss of the component intended function(s), as determined by engineering evaluation. By letter dated January 28, 2002, requested, in RAI B.3.32-1, the applicant to describe the criteria for assessing the severity of observed degradations and the need for corrective actions. In its response dated March 15, 2002, the applicant stated that the criteria would be developed at the time of the inspection. Criteria such as the ASME Code, results from additional inspections, and operating experience may be used to assess the severity of the degradation and the need for corrective action. Since the applicant indicated that acceptance criteria will be based on ASME Code requirements, results from additional inspections, and operating experience, the staff finds the applicant’s response reasonable and acceptable.

3.0.3.16.3 FSAR Supplement

The staff has reviewed Sections 18.2.24 of LRA Appendix A.2 and Section 18.2.25 of LRA Appendix A.1 and finds that the FSAR Supplements contain the appropriate elements of the program.

3.0.3.16.4 Conclusion

The staff reviewed Section B.3.32 of the LRA, the FSAR Supplement provided in Appendix A of the LRA, and the applicant's March 15, 2002, response to the staff's request for additional information. On the basis of this review and the above evaluation, the staff finds that the implementation of the Sump Pump Systems Inspection program provides reasonable assurance that the aging effects of loss of material will be managed such that components within the scope of license renewal will continue to perform their intended functions consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.17 Treated Water Systems Stainless Steel Inspection

Section B.3.34 of the LRA describes the applicant's Treated Water Systems Stainless Steel Inspection program for monitoring the aging of stainless steel components of unmonitored treated water systems. This one-time inspection is intended to detect the presence and extent of any loss of material or cracking of stainless steel components exposed to unmonitored treated water within these systems. The staff reviewed Section B.3.34 of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.17.1 Technical Information in the Application

The Treated Water Systems Stainless Steel Inspection program is described in Section B.3.34 of the LRA. The purpose of the program is to characterize the loss of material or cracking of stainless steel components resulting from exposure to unmonitored treated water environments. An unmonitored treated water environment is one that may contain conditions that can concentrate existing levels of contaminants or that may simply start with a higher level of contaminants than those systems routinely monitored by the Chemistry Control Program. The Treated Water Systems Stainless Steel Inspection includes a one-time inspection of stainless steel components, welds, and heat affected zones, as applicable, in the following systems:

- Containment valve injection water (Catawba only)
- Drinking water (Catawba only)
- Nuclear solid waste disposal (McGuire only)
- Solid radwaste (Catawba only)

For the McGuire nuclear solid waste disposal system, volumetric examinations will be conducted in stagnant and low flow lines around the spent resin storage tanks and a visual examination will be conducted of the interior of a valve to determine the presence of pitting corrosion. For Catawba, the volumetric examinations will be performed on the drinking water system because this system receives water from the local municipality. This water has contaminants levels in excess of limits below which a concern would not exist for cracking and loss of material in stainless steel, and is considered to bound the environments of the other Catawba systems within the scope of this inspection. In addition to the volumetric examination, a visual examination of the interior of a valve will be conducted to determine the presence of pitting corrosion.

3.0.3.17.2 Staff Evaluation

The staff's evaluation of the Treated Water Systems Stainless Steel Inspection program focused on the program elements rather than details of specific plant procedures. The staff evaluated how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures and work processes. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] The applicant identified the scope as stainless steel components exposed to unmonitored treated water environments in the following McGuire and Catawba systems:

- Containment valve injection water (Catawba)
- Drinking water (Catawba)
- Nuclear solid waste disposal (McGuire)
- Solid radwaste (Catawba)

Because the scope is comprehensive and includes systems and components representative of stainless steel components exposed to unmonitored treated water, the staff finds the scope to be acceptable.

[Preventive or Mitigative Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or to mitigate aging effects. Since this is a condition monitoring program, the staff did not identify the need for preventive or mitigative actions.

[Parameters Monitored or Inspected] The applicant stated that the parameter inspected by the Treated Water Systems Stainless Steel Inspection program is pipe wall thickness as an indicator of loss of material and evidence of cracking.

The staff notes that three factors have been identified that promote stress corrosion cracking of stainless steels: (1) metallurgical (sensitization), (2) stress level, and (3) environmental. The basis in the LRA for the proposed Catawba inspections only focused on the environment. By letter dated January 28, 2002, the staff requested, in RAI B.3.34-1, additional information regarding how the metallurgical and stress level factors were considered in the system susceptibility comparisons. In its response dated March 15, 2002, the applicant indicated that all three factors were considered and provided the following explanation of how it had evaluated environmental conditions:

> Environmental effects are the third parameter playing a role in promoting stress corrosion cracking. Dissolved oxygen and halogens are contributors to stress corrosion cracking of stainless steel. For the three Catawba systems within the scope of this one-time inspection, the Drinking Water System has the highest contaminant levels. This difference is the only clear cut distinction among the systems. The Containment Valve Injection Water System is filled with demineralized water. The Solid Radwaste System receives borated water from plant systems. Demineralized water and borated water used at Catawba contain lower levels of the contaminants known to be a concern for stress corrosion cracking than the Drinking Water System.
>
> While Duke does not believe that loss of material and cracking of stainless steel components within these systems is occurring, the aging effects could not absolutely be ruled out. Duke decided that an inspection was warranted and will focus on the Catawba Drinking Water System as the leading indicator for the Treated Water Stainless Steel Inspection.

Since the applicant does not believe that loss of material and cracking of stainless steel components within these systems is occurring, but could not rule out the potential for these aging effects, the applicant plans to perform this one-time inspection to characterize any loss of material or stress corrosion cracking of the stainless steel components in the treated water systems. Therefore, the staff finds the applicant's response to be acceptable.

Based on the information provided in the LRA and the applicant's response to the RAI, the staff finds that the parameters monitored are capable of detecting loss of material prior to loss of component function.

[Detection of Aging Effects] Section B.3.34 of the LRA states that the Treated Water Systems Stainless Steel Inspection is a one-time inspection that will detect the presence and extent of loss of material or cracking of stainless steel components exposed to unmonitored treated water environments. Because the volumetric and visual examinations are capable of detecting loss of material or cracking of stainless steel components exposed to unmonitored treated water environments, the Staff finds this acceptable.

[Monitoring & Trending] The applicant stated that it will perform a volumetric examination of various susceptible piping locations in the nuclear solid waste disposal system at McGuire and in the drinking water system at Catawba. These examinations will include a stainless steel welds and heat-affected zones since these are the likely locations for stress corrosion cracking to occur. The use of volumetric examinations, which evaluate the full volume of the piping, will ensure that unacceptable pipe flaws will be identified. In addition to the volumetric examination, the applicant will visually examine the interior of a valve to determine the presence of pitting corrosion. The program calls for a one-time inspection.

The staff finds that the volumetric examination techniques proposed are consistent with current industry practice. Furthermore, since this is a one-time inspection, trending inspection results is not necessary. Based on the staff's review of the application and the applicant's March 15, 2002, response to RAI B.3.34-1 (discussed under the Parameters Monitored or Trended element), the staff finds the monitoring activities to be appropriate to identify loss of material or defects.

[Acceptance Criteria] Section B.3.34 of the LRA states that the acceptance criteria for the inspection is no unacceptable loss of material that could result in the loss of the component intended function(s), as determined by engineering evaluation. By letter dated January 28, 2002, the staff requested, in RAI B 3.34-2, additional information regarding the criteria for assessing the severity of observed degradations and the need for corrective actions. In its response dated March 15, 2002, the applicant stated that the criteria would be developed at the time of the inspection. Criteria such as the ASME Code, results from additional inspections, and operating experience may be used to assess the severity of the degradation and the need for corrective action. Since the applicant referenced ASME Code requirements, results from additional inspections, and operating experience as the bases for its acceptance criteria, the staff finds the applicant's response reasonable and acceptable.

Because the methods to be used by the Applicant are capable of detecting defects or loss of material and the identification of these parameters will enable the Applicant to take corrective action prior to loss of component function, the Staff finds the acceptance criteria to be acceptable.

[Operating Experience] The applicant stated that the treated water systems stainless steel inspection is a one-time inspection, for which there is no operating experience. The staff agrees that there is no operating experience with this inspection at Catawba and McGuire. The staff finds this reasonable and acceptable.

3.0.3.17.3 FSAR Supplement

Appendix A-1, Section 18.2.26, and Appendix A-2, Section 18.2.25, the LRA provide FSAR Supplements for McGuire and Catawba, respectively. These sections describe the Treated Water Systems Stainless Steel Inspection program and are consistent with the program description in Section B.3.34. of the LRA. Therefore, the staff finds them acceptable.

3.0.3.17.4 Conclusions

The staff reviewed the information provided in Section B.3.34 of the LRA, the summary description in the FSAR Supplement in Appendix A of the LRA, and the applicant's March 15, 2002, responses to the staff's RAIs. On the basis of this review and the above evaluation, the staff finds that there is reasonable assurance that the aging effect of loss of material and cracking of the stainless steel piping and components within the scope of the program will be adequately managed such that the intended function will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.18 Underwater Inspection of Nuclear Service Water Structures

The applicant describes its underwater inspection of nuclear service water structures program in Section B.3.35 of the LRA. The applicant credits this inspection activity with managing the potential aging of nuclear service water (NSW) structures and components that are within the scope of license renewal. The inspection activity monitors and assesses the condition of NSW structures for loss of material of steel components and loss of material and cracking of concrete components. The staff reviewed Section B.3.35 of the LRA to determine whether the applicant has demonstrated that Underwater Inspection of Nuclear Service Water Structures program will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.18.1 Technical Information in the Application

Section B.3.35 of the LRA states that the purpose of the Underwater Inspection of Nuclear Service Water Structures program is to provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of equipment and components within the scope of 10 CFR Part 54 will be maintained consistent with the CLB for the period of extended operation. This program is credited with managing loss of material of steel and loss of material and cracking for concrete for the period of extended operation for the following structures:

McGuire:

- Standby nuclear service water discharge structures
- Standby nuclear service water intake structure

Catawba:

- Low pressure service water intake structure
- Nuclear service water intake structure
- Nuclear service water pump structure
- Standby nuclear service water discharge structures
- Standby nuclear service water intake structure
- Standby nuclear service water pond outlet

The underwater inspection of nuclear service water structures program detects aging effects through visual examination. The inspection is performed every five years at McGuire. At Catawba, the inspection is performed every Unit 1 refueling outage for the NSW structure and standby nuclear service water intake structures, and every five years for other structures. The acceptance criteria are: no unacceptable visual indication of (1) loss of material for steel components and (2) loss of material and cracking for concrete components, as determined by the “accountable engineer.” Structures and components that do not meet the acceptance criteria are evaluated by the accountable engineer for continued service, and are repaired as required. Structures and components which are deemed unacceptable are documented under the corrective action program. Specific corrective actions and confirmatory actions, as needed, are implemented in accordance with the corrective action program. The applicant stated that a review of previous inspections indicates that the standby nuclear service water intake and discharge structures at McGuire are in good working condition. At Catawba, previous inspections of NSW structures have revealed only minor degradation. No deterioration that could cause loss of intended function has been identified from the previous inspections.

3.0.3.18.2 Staff Evaluation

The staff's evaluation of the Underwater Inspection of Nuclear Service Water Structures program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective action program, while the administrative controls are governed by SLCs and implemented through plant procedures and the site work processes. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] Section B.3.35 of the LRA states that the following structures and components credit the Underwater Inspection of Nuclear Service Water Structures program:

McGuire:
Standby nuclear service water discharge structures
Standby nuclear service water intake structure
Catawba:

- Low pressure service water intake structure
- Nuclear service water intake structure
- Nuclear service water pump structure
- Standby nuclear service water discharge structures
- Standby nuclear service water intake structure
- Standby nuclear service water pond outlet

The scope covers the in-scope structures that are exposed to pond water at McGuire and pond or lake water at Catawba, and is therefore acceptable to the staff.

[Preventative Actions] There are no preventative actions taken as part of this program, and the staff did not identify the need for any preventative actions.

[Parameters Monitored or Inspected] Section B.3.35 of the LRA identifies loss of material for steel components and loss of material and cracking for concrete components as the parameters that can be detected by visual inspection. Because visual inspection can be used to identify the degraded conditions noted by the applicant, such inspections of the nuclear service water structures are acceptable to the staff.

[Detection of Aging Effects] Section B.3.35 of the LRA states that visual inspection will detect loss of material for steel components and loss of material and cracking for concrete components prior to the loss of structure or component intended functions. The use of visual inspection is considered by the staff to be a reasonable means of detecting these aging effects before the loss of intended function, and is consistent with NRC and industry guidance. Therefore, the staff finds this acceptable.

[Monitoring and Trending] Section B.3.35 of the LRA states that the inspections are performed every five years at McGuire, every Unit 1 refueling outage for Catawba NSW and standby nuclear service water intake structures, and every five years for the other Catawba structures.

No actions are taken as part of the program to trend the inspection results, but the inspection reports are retained in sufficient detail to permit confirmation of the inspection programs. Since structures and components that do not meet the acceptance criteria are evaluated for continued service and repaired as required, and since corrective actions and confirmatory actions, as needed, are implemented in accordance with the corrective action program, the staff finds this acceptable.

[Acceptance Criteria] Section B.3.35 of the LRA states that the acceptance criteria is no unacceptable visual indication of (1) loss of material for steel components and (2) loss of material and cracking for concrete components, as determined by the “accountable engineer.”

Since the assessment of the severity of the observed degradation and determination of whether corrective action is necessary is based on the judgement of the accountable engineer, by letter dated January 28, 2002, the staff requested, in RAI B.3.35-1, additional information regarding the qualifications of the accountable engineer. In its response dated March 11, 2002, the applicant stated that the accountable engineers qualifications are in accordance with RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants.” Because the acceptance criteria are consistent with the degradation of concern, which is detectable by visual inspections, and because the inspections and evaluations will be conducted by knowledgeable and experienced individuals with qualifications in accordance with RG 1.127, the staff finds this acceptable.

Since the LRA is not clear regarding the extent to which a loss of material or cracking is acceptable, by letter dated January 28, 2002, the staff requested, in RAI B.3.35-2, a description of the criteria for (1) assessing the severity of the observed degradations; and (2) determining whether corrective action is necessary. In its response dated March 11, 2002, the applicant stated that the examination and assessment of the structure’s condition follows the guidance of RG 1.127, ACI 349.3, “Evaluation of Existing Nuclear Safety-Related Concrete Structures, and ACI 201, “Guide for Making a Condition Survey of Concrete in Service.” In addition, the applicant stated that the visual inspections for these types of degradation have been addressed in NRC Inspection Procedure 62002, “Inspection of Structure, Passive Components, and Civil Engineering Features at Nuclear Power Plants,” and NEI 96-03, “Industry Guideline for Monitoring Structures.” Since the inspections use the appropriate guidance, as listed above, the staff finds this acceptable.

[Operating Experience] Section B.3.30 of the LRA describes the plant-specific operating experience related to the underwater inspections of the nuclear service water structures. At McGuire, a review of previous inspection reports indicates the standby nuclear service water intake and discharge structures are in good working condition. McGuire’s old, galvanized steel trash racks and fasteners were noted to be degraded when they were replaced in 1992 with stainless steel trash racks. At Catawba, previous inspections have revealed only minor degradation: no deterioration that could cause a loss of intended function has been identified. The staff finds that the McGuire and Catawba operating experience indicates that the underwater inspection activities of the NSW structures are effective in managing the aging effects of the structures.

3.0.3.18.3 FSAR Supplement

The staff reviewed Section 18.2.27 and Section 18.2.26 of the FSAR Supplements for McGuire and Catawba, respectively, in Appendix A of the LRA. The staff finds that some important industry standards and the NRC guidelines used for the AMP are not incorporated in the FSAR Supplements. The applicant is requested to update the FSAR Supplement to incorporate those standards and guidelines. This issue is characterized as open item 3.0.3.18.3-1.

3.0.3.18.4 Conclusions

The staff has reviewed the information provided in Section B.3.35 of the LRA and the summary description of the flood barrier seal inspection activities in Appendix A of the LRA. In addition, the staff considered the applicant’s March 11, 2002, response to the staff’s RAIs. On the basis of this review and the above evaluation, the staff finds that the Underwater Inspection of Nuclear Service Water Structures program will adequately manage the aging effects such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.4 Quality Assurance Program

The staff reviewed LRA Section B.2, "Program and Activity Attributes," to verify that AMPs were described in accordance with 10 CFR 54.21(a)(3) and 10 CFR 54.21(d). In Section B.2, the applicant described its quality assurance program information with respect to the various AMP elements. The staff’s evaluation of the AMPs focused on how the AMP manages aging effects through the effective incorporation of the following ten elements: program scope, preventative actions, parameters monitored or inspected, detection of aging effect, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The particular aspects reviewed by the staff in this section encompass three quality assurance program attributes: corrective actions, confirmation process, and administrative controls. These three attributes of the quality assurance program are addressed for all of the applicant’s AMPs.

The license renewal applicant is required to demonstrate that the effects of aging on structures and components that are subject to an AMR will be adequately managed to ensure that their intended functions will be maintained in a manner that is consistent with the CLB of the facility throughout the period of extended operation, as required by 10 CFR 54.21(a)(3). Therefore, those aspects of the aging management process that affect the quality of safety-related SSCs are subject to the quality assurance requirements of Appendix B to 10 CFR Part 50. For non-safety-related SSCs that are subject to an AMR, the existing 10 CFR Part 50, Appendix B, quality assurance program may be used by the applicant to address the attributes of corrective actions, confirmation process, and administrative controls.

Summary of Technical Information in Application

Section B.2 of Appendix B to each LRA, the applicant provides a general description of the corrective actions, administrative controls, and confirmation process common to aging management programs for SSCs within the scope of license renewal. The applicant’s programs and activities that are credited with managing the effects of aging can be divided into new and existing programs. As described in Section B.2 of Appendix B to each LRA, the applicant uses the following specific attributes to describe these programs and activities:

Scope: an identification of the specific structures or components managed by the program or activity.

Preventive Actions: a description of the actions taken in the period of extended operation to either prevent aging effects from occurring or mitigate (i.e., lessen or slow down) aging degradation for prevention and mitigation programs. This attribute is not applicable for one-time inspections, condition monitoring and performance monitoring programs.

Parameters Monitored or Inspected: a description of what is being monitored or inspected for all inspections and programs. These descriptions include the observable parameters or indicators to be monitored or inspected for each aging effect managed. The observable parameters should be linked to the degradation of the structure or component intended functions in the period of extended operation.

Detection of Aging Effects: the detection of aging effects should occur before there is a loss of structure and component intended function(s).

Monitoring & Trending: a description of when, where and how program data is collected; i.e., all aspects of activities to collect data as part of the program. This description includes aspects such as method or technique (e.g., visual, volumetric, surface inspection), frequency, sample size, and timing of new/one-time inspections. This attribute also provides information that links the parameters to be monitored or inspected to the aging effects being managed. Trending is a comparison of the current monitoring results with previous monitoring results in order to make predictions for the future and to initiate actions as necessary.

Acceptance Criteria: a description of the acceptance criteria for ensuring the structure or component intended function is maintained during the period of extended operation. The acceptance criteria may be based on design or current licensing basis information as well as established industry codes or standards.

Corrective Action & Confirmation Process: a description of the actions to be taken in the period of extended operation when the acceptance criteria or standard is not met. The corrective action and confirmation process that is described for each aging management program or activity applies to all structures and components within the scope of the program or activity. In some cases the program itself includes its own corrective action and confirmation process.

In other cases, the corrective action process is credited for corrective action and confirmation process. The corrective action process is a formal corrective action program which facilitates the correction of conditions adverse to quality. Corrective actions are documented. Data are periodically reviewed to identify positive or negative changes and to initiate additional actions, as necessary. The corrective action process is implemented by Nuclear System Directives NSD 208, Problem Investigation Process and NSW 223, Trending of PIP Data.

Administrative Controls: a description of the administrative structure under which the programs and activities are executed. Examples of various administrative structures include program manuals, nuclear station directives, engineering support documents, plant procedures, and work orders. The administrative controls provide for a review and approval process.

Operating Experience: the objective evidence that supports the determination that the program or activity provides reasonable assurance that the effects of aging will be adequately managed such that the structure or component intended function(s) will be maintained consistent with the current licensing basis during the period of extended operation (i.e., 20 years from the end of the initial operating license).

Staff Evaluation

The staff evaluated aspects of the applicant's quality assurance program as it relates to the AMP activities defined in Section A, "UFSAR Supplements," and Appendix B, "Aging Management Activities," of the applicant's LRA.

10 CFR 54.21(a)(3) requires a license renewal applicant to demonstrate that the effects of aging on structures and components subject to an aging management review will be adequately managed to ensure that their intended functions will be maintained consistent with the current licensing basis of the facility for the period of extended operation. Consistent with this approach, the applicant's aging management programs should contain the elements of corrective action, confirmation process, and administrative controls in order to ensure proper management of the aging programs.

Appendix B, "Aging Management Programs and Activities," Section B.2, "Program and Activity Attributes," Subsection B.2.2, "Attribute Definitions," of the LRA stated that the applicant relied on the corrective action process as implemented through Nuclear System Directive (NSW) 208, "Problem Investigation Process (PIP)," and NSW 223, "Trending of PIP Data," to satisfy the corrective actions, confirmation process, and administrative controls attributes of the aging management programs that will be implemented at Catawba and McGuire for the period of extended operation.

Consistent with guidance in S.P.-LRA, Appendix A.2, "Quality Assurance for Aging Management Programs (Branch Technical Position HQMB-1)," license renewal applicants can rely on the existing requirements in 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to satisfy these program elements/attributes. However, the Catawba/McGuire LRA did not establish or identify the role of the aforementioned NODS with respect to the applicant's 10 CFR Part 50, Appendix B, quality assurance program in effect at these facilities.

For non-safety-related structures and components that are subject to an AMR for license renewal, an applicant has an option to expand the scope of its 10 CFR Part 50, Appendix B, program to include these structures and components to address corrective actions, confirmation process, and administrative controls for aging management during the period of extended operation. In accordance with Appendix A.2, "Quality Assurance for Aging Management Programs (Branch Technical Position IAMB-1)," Section A.2.2, Item 2 to the draft S.P., the applicant should document a commitment to expand the scope of its 10 CFR Part 50, Appendix B, quality assurance program to include non-safety-related structures and components in the FSAR supplement consistent with LRA Section B.2. By letter dated January 17, 2002, the staff requested, in RAI 2.1-3, the applicant to confirm that NODS 208 and 223 govern the applicant's corrective action program, which is subject to the requirements of 10 CFR Part 50, Appendix B, Quality Assurance program requirements. In its response dated March 1, 2002, the applicant confirmed that the scope of the quality assurance program was expanded to include both safety-related and non-safety-related SSCs within the scope of license renewal. The staff finds that committing to the applicant's quality assurance program for all aging management programs for safety-related and non-safety-related SSCs within the scope of license renewal is an acceptable approach to meeting Branch Technical Position HQMB-1.

In RAI 2.1-3, the staff requested the applicant to describe how the programs described in NSW 208 and NSW 223 would satisfy the requirements of 10 CFR Part 50, Appendix B, "Quality Assurance Program," for SSCs subject to an aging management program at Catawba and McGuire during the period of extended operation. In its March 1, 2002, response to RAI 2.1-3, the applicant indicated that NSW 208, "Problem Investigation Process," provided a structured approach for a formal corrective program that facilitates the prioritization, evaluation, and correction of conditions adverse to quality, as defined by 10 CFR Part 50, Appendix B. "Trending of PIP Data," (NSW 223), provided a process for an effective, structured method for analyzing PIP data. As stated in each aging management program and activity description provided in Appendix B of the Application, this same corrective action program is credited for systems, structures, and components whose aging will be managed by these aging management programs and activities at Catawba and McGuire during the period of extended operation. Since the applicant's descriptions of these programs indicate that the programs meet regulations governing the quality assurance program, the staff finds this response acceptable.

<u>Programs and Activities, FSAR Supplement</u>

The applicant has provided a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation in FSAR Chapter 18, which also is included in Appendices A.1 and A.2 to the LRA. The FSAR supplement provides a brief explanation of the new and existing programs that the applicant will use to manage the effects of aging. The explanation contains a summary of several important attributes of aging management programs, as defined in NEI 95-10 and S.P.-LRA, such as inspections and techniques used to identify aging effects.

In conformance with 10 CFR 54.21(d) requirements, the applicant needed to describe how the programs described in NSW 208 and NSW 223 would satisfy the requirements of 10 CFR Part 50, Appendix B, "Quality Assurance Program," for SSCs subject to an aging management program as a commitment in the FSAR Supplements for Catawba and McGuire. In is March 1, 2002, response to RAI 2.1-3, the applicant indicated that the following statement would be added to Section 18.1 of the McGuire and Catawba FSAR Supplements:

> The PIP NSW 208 provides a structured approach for a formal corrective action program that facilitates the prioritization, evaluation, and correction of conditions adverse to quality, as defined by 10 CFR Part 50, Appendix B. This same corrective action program is credited for systems, structures, and components whose aging will be managed by the aging management programs and activities described herein.

Since the applicant indicated that the FSAR Supplements would be updated to reflect the role of NSW 208 and NSW 223 in its 10 CFR Part 50, Appendix B, quality assurance program for SSCs subject to an aging management program during the period of extended operation, the staff finds its response acceptable.

Conclusion

The staff finds that the quality assurance attributes are consistent with 10 CFR 54.21(a)(3). Therefore, the applicant's quality assurance description for its aging management programs is acceptable. The staff finds that the applicant's FSAR supplement and update thereto in accordance with the March 1, 2002, response to the staff's RAI provides a sufficient description of the quality assurance programs and attributes and activities for managing the effects of aging.

3.1 Aging Management of Reactor Vessel, Internals, and Reactor Coolant System

The LRA includes the following reactor coolant mechanical components at Catawba and McGuire that require an AMR:

- reactor coolant piping and associated connections to other support systems (including reactor coolant pumps and inter-connected piping, pipe fittings, valves, and bolting)
- reactor vessels (including the control rod drive mechanisms)
- reactor vessel internals
- pressurizers (including safety relief valves and pressure relief tank)
- steam generators

Each reactor coolant system (RCS) at Catawba and McGuire consists of four primary piping loops interconnected at the reactor vessel. Each loop contains one reactor coolant pump (RCP), one steam generator, valves, and interconnecting piping. The pressurizer, connected to one of the hot legs, provides a means for controlling RCS pressure changes during reactor operations. The RCS also contains piping and components that allow venting of the reactor vessel and pressurizer.

The reactor coolant piping at Catawba and McGuire consists of Class 1 and non-Class 1 components. The applicant describes the system boundaries for the Class 1 RC piping and associated components in Section 2.3.1 of the LRA, "Reactor Coolant System," and for the non-Class 1 components in Section 2.3.3.32 of the LRA, "Reactor Coolant System (non-Class 1 components)." The non-Class 1 portions of the RCS (excluding the RCP motor oil collection sub-system) are relied upon to provide and maintain containment isolation and maintain system pressure boundary integrity. The reactor vessel leak-off lines are included within this set of components and are relied upon only in the event the reactor vessel flange inner seal leaks. The results from AMR for the non-Class 1 portions of the RCS are described in Section 3.3 of the LRA, "Aging Management of Auxiliary Systems," and are summarized in Table 3.3-41 of the LRA. The staff's evaluation of Section 3.3 of the LRA is described in Section 3.3 of this SER.

The applicant describes the results from AMR for the Class 1 portions of the RCS, including the reactor vessels, reactor vessel internals, pressurizers, steam generators, and Class 1 piping, valves, and pumps, in Section 3.1 of the LRA, "Aging Management of Reactor Vessel, Internals, and Reactor Coolant System." Table 3.1-1 of the LRA, "Aging Management Review Results - Reactor Coolant System," summarizes the results from AMR for these RCS components. The applicant describes the applicable AMPs for these components in Appendix B of the LRA, "Aging Management Programs and Activities." This section of the SER includes the staff's review of the AMR results presented in Section 3.1 of the LRA and includes the mechanical components for all five RCS subsystems identified above.

3.1.1 Reactor Coolant Class 1 Piping, Valves and Pump Casings

The Westinghouse-supplied primary piping includes branch connection nozzles and special items such as resistance temperature detector (RTD) scoop elements, pressurizer spray scoop, sample connection scoop, reactor coolant temperature element installation boss, and the temperature element well itself.

ASME Class 1 piping includes piping connected to the Westinghouse supplied primary loop piping out to and including (1) the outermost containment isolation valve in piping which penetrates primary containment, or (2) the second of two valves normally closed during normal reactor operation in piping which does not penetrate primary containment. Some branch connections and instrument connections in the RCS are equipped with 3/8 inch ID flow restricting orifices that limit the maximum flow from a break downstream of the flow restrictor to below the makeup capability of the RCS. This orifice is used to establish the division from Class 1 to Class 2 instead of double isolation valves.

For Class 1 valves, the pressure-retaining portion of the component consists of the valve body, bonnet and closure bolting. The valves are welded in place with the exception of the pressurizer safety valves that have flanged connections. For the reactor coolant pumps, the pressure-retaining portion includes the pump casing, the main closure flange, the thermal barrier heat exchanger within the RCP, the RCP seals and the pressure-retaining bolting.

3.1.1.1 Technical Information in the Application

The applicant identifies the Class 1 RCS piping, valves and pumps within the scope of license renewal in Section 2.3.1.2 of the LRA. In Section 3.1 of the application, the applicant describes its AMR process for ASME Code Class 1 components and the aging management programs (AMPs) that will be used to manage aging effects in these components during the periods of extended operation for the McGuire and Catawba units. In Table 3.1-1 of the application, the applicant identifies that the following Class 1 RCS piping, valves and pumps within the scope of license renewal require aging management reviews:

1. the Westinghouse-supplied primary loop Class 1 piping of the RCS pressure boundary that are connected to the reactor vessel, the steam generators (primary side), and the RCP
2. the Duke-designed Class 1 piping of other support systems that are attached to the primary loop piping
3. pressure boundary portion of Class 1 valves (bodies and bonnets, bolting)
4. pressure boundary portion of the RCP (casing, main closure flange, thermal barrier heat exchanger and bolting)

The applicant described its AMR of the Class 1 piping and associated components for license renewal in Section 3.1.1 of the LRA, "Aging Management Review Results Tables," and in Table 3.1-1 of the application. The staff reviewed this section of the LRA to determine whether the applicant had demonstrated that the effects of aging on the RC Class 1 piping, valves, and pump casings will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The applicant stated that the RCS Class 1 piping, valve and pump components within the scope of license renewal have been designed to meet the requirements of ASME Boiler and Pressure Vessel Code, Section III, Subsection NB for Class 1 components. The predominant material of construction for the Class 1 components, including piping and pipe fittings, is stainless steel, including cast austenitic stainless steel (CASS). The internal surfaces of all Class 1 piping and associated components wetted by borated water are stainless steel. Some bolting and exterior surfaces of the pressure boundary components are identified as carbon or low alloy steel. Design and welding considerations in the selection of materials for RCS components reduce the susceptibility of Class 1 piping and component materials to sensitization.

The Class 1 piping and associated components that are within the scope of license renewal are internally exposed to borated reactor coolant water at approximately 315.6 ^{o}C (600 ^{o}F) and 15.41 MPa (2235 psig). These components are located in the reactor building (i.e., containment) and are externally exposed to an air environment. External surfaces near mechanical piping connections (e.g., flanges) may also be exposed to borated water leakage. The thermal barrier heat exchangers for the RC pumps are also exposed to treated water.

The applicant did not specifically identify any TLAA in Section 3.1.1 of the LRA that is applicable to Class 1 piping and associated components. However, Section 4.0 of the LRA includes the following TLAAs applicable to RC piping and associated components:

- metal fatigue for ASME Class 1 components
- RCP flywheel fatigue
- leak-before-break analyses

3.1.1.1.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identifies the following aging effects for the RCS Class 1 piping and associated components that are subject to an AMR:

- cracking
- loss of material
- reduction in fracture toughness
- loss of preload

3.1.1.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant identifies three AMPs to manage the aging effects associated with the RCS Class 1 piping and associated components. The AMPs are:

- Chemistry Control program
- Fluid leak Management program
- ISI Plan

The applicant stated that these AMPs are “equivalent or similar to the corresponding program/activity that has been previously reviewed and found acceptable by the staff during the Oconee License Renewal review, as documented in NUREG-1723.” The applicant concluded that these AMPs will manage the effects of aging such that the intended function of the RCS Class 1 piping and associated components will be maintained consistent with the CLB under all design loading conditions throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.1.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Sections 3.1.1 and 3.1.2, and in Table 3.1-1 of the LRA and pertinent sections of Appendices A and B to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended function(s) of the RCS Class 1 piping and associated components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

Table 3.1-1 of the LRA lists the Class 1 portions of the RCS piping and associated pressure boundary components that are within the scope of the license renewal and require aging management reviews, identifies the aging effects that require management for these components, and identifies the aging management programs that will be used to manage these effects.

3.1.1.2.1 Aging Effects

In accordance with Section 3.1 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the RCS piping and associated pressure boundary components to provide reasonable assurance that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for Catawba and McGuire. This also included the plant-specific operating experience at both subject plants.

The material of construction for the RCS Class 1 piping and associated components subject to an AMR is primarily stainless steel (including CASS) for pipe fittings, pump casings, and valve bodies. Carbon steel and low alloy steel are used for RCP main flange bolting. Most RCS piping and associated components are exposed to borated water, treated water, and/or air. The applicant performed a review of industry experience and NRC generic communications relative to the RC piping and associated components to provide reasonable assurance that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for Catawba and McGuire. This review also included a review of plant-specific operating experience at both plants. Table 3.1-1 of the LRA identifies that the following aging effects are applicable to the RCS Class 1 piping and associated components requiring AMRs:

- cracking and loss of material of stainless steel components (including CASS) in borated water (internal surfaces)
- loss of material from carbon steel and low-alloy steel components in the reactor building environment (external surfaces)
- reduction in fracture toughness of CASS components (including valve bodies and bonnets, and the CASS McGuire 1 27.5" ID Loop B elbow) in a high-temperature borated water environment
- loss of preload of ASME Class 1 stainless steel and low alloy steel bolting in the reactor building (i.e., air) environment

Loss of material due to erosion, or general corrosion is not normally an issue for austenitic stainless steel (including CASS) RCS piping, pump, and valve components because the materials are normally inherently tough and resistant to general corrosion; however, loss of material may be an applicable effect for these components under wet conditions if the components have creviced areas that may be exposed to the fluids. Loss of material in the stainless steel components if the components are subject to wear. The applicant has identified that loss of material is an applicable aging effect for all stainless steel Class 1 RCS piping, pump, and valve components that are exposed on their interior surfaces to borated or treated water environments. This is acceptable because it conservatively accounts loss of material that could be induced by these aging mechanisms, even though these components do not normally have creviced areas or are not normally subject to wear.

The RCP main flange bolting made out of low alloy steel (ferritic fasteners) are susceptible to loss of material due to corrosion. The applicant has identified that loss of material due to boric acid-induced corrosion, and specifically due to potential leakage of boric acid to external surfaces of Class 1 RCS components made from carbon or low-alloy steel (including bolted connections, and integral attachments and supports) is a potential aging effect requiring aging management. This is consistent with the staff's discussion of boric acid corrosion events that have occurred in the industry and that are summarized in NUREG/CR-5576, "Survey of Boric Acid Corrosion of Carbon Steel Components in Nuclear Plants." The applicant's identification that loss of material is an applicable effect for Class 1 RCS components made from carbon steel or low-alloy steel is acceptable because it agrees with the staff's determination in NUREG/CR-5576 that loss of material resulting from postulated leakage of the primary coolant (i.e., postulated borated water leakage) is an applicable aging effect for PWR RCS components made from carbon steel or low alloy steel.

Irradiation embrittlement is not a concern for the RCS piping and associated components because the expected neutron fluence is much less than the threshold level at which changes in properties of the material would occur. However, the applicant has identified that CASS components may be susceptible to loss of fracture toughness as a result of thermal aging. The loss in fracture toughness reduces the critical flaw sizes for CASS components. Components fabricated from CASS that have delta ferrite levels below the susceptibility screening criteria have adequate fracture toughness and do not require any supplemental inspection. As a result of thermal embrittlement, components that have a delta ferrite level exceeding the screening criterion may not have adequate fracture toughness and require additional evaluation or examination. The applicant evaluated all RC piping components (i.e., piping components, valve bodies, and RCP casing and main flanges) fabricated from CASS using the criteria delineated in the May 19, 2000, letter to NEI from NRC. Based on this evaluation, the McGuire 1, Primary Loop, 27½ inch ID, Loop B cold leg elbow is the only ASME Class 1 piping component that exceeds the NRC established threshold for susceptibility to thermal embrittlement and requires aging management. This is in accordance with the staff's analysis in its Interim Staff Guidance on CASS that was issued by NRC on May 19, 2000.[1] The applicant's identification that loss of fracture toughness is an applicable effect only for McGuire 1, Primary Loop, 27½ inch ID, Loop B cold leg elbow made from CASS is acceptable to the staff because the applicant's inclusion

1 Letter from C. I. Grimes (NRC) to D. J. Walters (NEI), *License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components,* Project No. 690, dated May 2000.

of this aging effect for the McGuire 1, Primary Loop, 27½ inch ID, Loop B cold leg elbow and omission of this effect for other CASS RCS piping components at McGuire and Catawba have based on the analytical methods for evaluating CASS RCS components for thermal aging, as given in the interim staff guidance that was issued to the NEI and nuclear power industry.[1]

The RCS piping and pipe fittings, valve bodies larger than 4-inch nominal pipe size, and the RCP pressure boundary closure components may be susceptible to cracking by thermal fatigue. The applicant addresses this issue as a time limited aging analysis (TLAA) in Section 4.3 of the application. The staff's evaluation of this TLAA is documented in Section 4.3 of this application.

Austenitic stainless steel is known to be susceptible to stress-corrosion cracking if the external surface of the pipe or component comes in contact with halogen levels exceeding 150 ppb or sulfate levels exceeding 100 ppb. The applicant has identified in Table 3.1-1 of the application that cracking is an applicable effect for Class 1 stainless steel piping, valve, or pump components exposed to borated/treated water environments. Although, the McGuire UFSAR Section 5.2.3.3 and the Catawba UFSAR Section 5.2.3.2.3 state that stress-corrosion cracking of the austenitic stainless steel is not a concern because exposure to halogen or sulfates is unlikely, the staff concurs that halogen-induced stress corrosion cracking is a potential aging effect for austenitic stainless steel components that are exposed to borated/treated water environments. The applicant's identification of cracking as an applicable effect for austenitic stainless steel RCS piping components is acceptable because the scope of this general classification covers cracking of stainless steel components that could be induced by both stress corrosion and by thermal fatigue. Thermal fatigue of the RCS piping components is further assessed by the staff in Section 4.3 of this SER.

The applicant has identified that loss of preload due to stress relaxation is an aging effect applicable for bolted closures on the reactor coolant pumps (RCPs) and RCS valves. This is acceptable to the staff because it is agreement with Table 3.1-1 of NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," which identifies that loss of preload is an applicable effect for bolted connections in the RCS.

On the basis of the description of the internal and external environments, materials used, and the applicant's review of industry and plant-specific experience, the staff concludes that the applicant has identified all aging effects that are applicable for the Class 1 portion of the RC piping and associated components.

3.1.1.2.2 Aging Management Programs

The applicant identified existing programs for managing aging effects for the RCS Class 1 piping and associated components during the license renewal term. The applicant identified the following AMPs for managing the aging effects associated with the Class 1 RCS piping, pumps, and valves:

- Fluid Leak Management program for the external surfaces of ferritic carbon steel or low-alloy steel components that could be potentially exposed to borated water leakage

- the Chemistry Control program and the ISI Plan for CASS components and stainless steel piping, fittings, and branch connections

- the Chemistry Control program alone for stainless steel orifices, valve bodies and bonnets, and thermal barrier heat exchanger tubing

The Fluid Leak Management program (Section B.3.15 of Appendix B to the LRA) was developed by the applicant in response to NRC Generic Letter 88-05. Inspections are performed to provide reasonable assurance that borated water leakage from the reactor coolant pressure boundary does not lead to undetected loss of material on the external surface of RC piping and associated components, and specifically for those made out of carbon steel or low alloy steel. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0.

For the Class 1 RCS piping components, the ISI Plan (Section B.3.20 of Appendix B to the LRA) manages the aging effects of loss of material, cracking, gross loss of preload, and gross reduction in fracture toughness. The scope of the ISI plan for Class 1 components complies with the requirements of ASME Section XI, Subsections IWB. Depending on the examination category, the methods of inspections may include visual, surface and/or volumetric examination of weld locations susceptible to aging degradation. The examination methods required by Subsection IWB for implementation either directly inspect for loss of material and cracking in the Class 1 components and are capable of detecting the aging effects, or inspect for indications of reactor coolant leakage which, in the case of bolted connections, would be indicative of a loss of preload in the bolt. The ISI Plan also indirectly monitors for loss of fracture toughness in CASS Class 1 components that are susceptible to thermal aging (i.e., the McGuire 1, Primary Loop, 27½ inch ID Loop B cold leg elbow). The ISI plan is credited with managing the aging effects of several components in different structures and systems and is therefore considered a common aging management program. This is discussed in detail in the following paragraph. The staff has evaluated this common AMP and, with the exception of open item 3.0.3.10.2-1 pertaining to volumetric examination of small-bore piping, found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

The McGuire 1, Primary Loop, 27½ inch ID Loop B, CASS cold leg elbow is fabricated from SA-351 CF8, statically cast, and contains no niobium. The ferrite number is calculated at 22 percent using Hull's equivalent factors. As part of the ISI plan, the McGuire 1 cold leg elbow is included in the ASME Section XI, Subsection IWB and IWC inspections in Section B.3.20.1 of the LRA. The applicant has stated it will perform an augmented inspection with applicable criteria from Code Case N-481 to manage reduction of fracture toughness by thermal embrittlement in the cold leg elbow during the period of extended operation. The staff accepted this Code Case for implementation in Revision 12 of Regulatory Guide 1.147 (May 1999). The augmented inspections will include a VT-2 visual examination of the elbow's exterior surface during the system leakage test that is performed each outage and a VT-1 visual examination of the welded joints that connect the elbow to adjacent piping segments prior to entering the period of extended operation. These two visual examinations will be repeated in the fifth and sixth ISI intervals. A detailed evaluation to demonstrate the integrity and serviceability of the elbow will be performed by June 12, 2021 (i.e., end of the initial license of McGuire 1).

The Chemistry Control program (Section B.3.6 of Appendix B to the LRA) provides water quality that is compatible with the materials of construction used in the Class 1 piping and associated components in order to minimize loss of material and cracking. This program is developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The Chemistry Control program is credited with managing the aging effects of several components in different structures and systems and is, therefore, considered a common aging management program. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is provided in Section 3.0 of this SER. However, the staff identified RAI 3.1.1-1, which addresses how the Chemistry Control program by itself would be capable of managing cracking in some of the Class 1 RCS piping components that were evaluated by the applicant in Table 3.1-1 of the application. The issue raised in RAI 3.1.1-1 and the steps taken by the applicant to resolve it is discussed in more detail in the following paragraphs.

In accordance with Table 3.1-1, the applicant identified that the chemistry control program will be used to manage the loss of material and cracking in RCS Class 1 orifices, valve bodies/bonnets and thermal barrier heat exchanger tubing. By letter dated January 28, 2002, the staff requested, in RAI 3.1.1-1, the applicant to clarify how the aging effects associated with orifices are adequately managed without some verification of the effectiveness of the chemistry control program (e.g., ISI or performance monitoring). In its response dated April 15, 2002, the applicant stated that the chemistry control program maintains the environment in the RCS by controlling contaminants that could lead to loss of material and cracking. The applicant also stated that its basis for concluding that the chemistry control program would be sufficient to manage loss of material and cracking in the orifices, was that the applicant's review of pertinent operating experience had not yet identified any failure of these components and, therefore, no supplemental inspection activities would be necessary for managing these aging effects during the periods of extended operation. The staff determined that the applicant's response to RAI 3.1.1-1 did not resolve the issue regarding how the Chemistry Control program, by itself, would be sufficient to manage loss of material and cracking in these orifices. The staff therefore concluded that some type of acceptable inspection program would be needed to manage these effects in the orifices as well. The staff's resolution of this issue is addressed in the following three paragraphs.

Table IWB-2500-1 to Section XI of the ASME Boiler and Pressure Vessel Code (henceforth Section XI) provides the following inspection requirements for orifices, valve bodies/bonnets, and tubing:

- Examination Category B-P, All Class 1 Pressure Retaining Components for Class 1 piping, valves and heat exchangers - system leak test and VT-2 visual examination of the pressure retaining boundary every refueling outage.

- Examination Categories BM1 and BM2, "Pressure Retaining Welds in Pump Casings and Valve Bodies," and "Pump Casings and Valve Bodies " (respectively):

    - Welds in valve bodies less than 4 inches in diameter - surface examination once an ISI inspection interval
    - Welds in valve bodies greater or equal to 4 inches in diameter - volumetric examination once an ISI inspection interval
    - Valve bodies exceeding 4 inches in diameter - visual VT-3 of the internal surfaces once an inspection interval.

Based on these requirements, the staff noted that the ISI Plan for McGuire and Catawba were not credited as an AMP to manage loss of material and cracking in the stainless steel ASME Code Class 1 orifices, valve bodies/bonnets and thermal barrier heat exchanger tubing in the same manner it was credited to manage these effects in the McGuire and Catawba ASME Code Class 1 CASS components and Code Class 1 stainless steel piping. By letter dated June 26, 2002, the staff indicated that potential open item 3.1.1-1 was identified to address the unresolved issue raised in RAI 3.1.1-1. In potential open item 3.1.1-1, the staff asked the applicant why it had not credited the ISI Plan for managing these aging effects for ASME Code Class 1 orifices, valve bodies/bonnets and thermal barrier heat exchanger tubing in the same manner it had credited the ISI Plan to manage these effects in the ASME Code Class 1 components made from CASS materials and Code Class 1 piping made from austenitic stainless steel. By letter dated July 9, 2002, the applicant stated that it will take the following actions to resolve the issue of aging management for those components where the Chemistry Control program was identified as the sole program for managing aging effects in these components:

> 1. Supplement Table 3.1-1 of the application by deleting the line item "Orifices" on page 3.1-7, row 3, and to include these components under the line entry entitled "Pipe and Fittings NPS @ 1 inch" on page 3.1-6, row 5 of the table, and notes that both the Chemistry Control Program and Inservice Inspection Plan will manage aging of the piping components.
>
> 2. Supplement Table 3.1-1 of the application by modifying the line item "Forged Stainless Steel Valve Bodies and/or Bonnets" on page 3.1-7, row 4, to add the Inservice Inspection Plan as an additional AMP to the Chemistry Control Program for managing aging in forged stainless steel valve bodies and bonnets.
>
> 3. Supplement Table 3.1-1 of the application by modifying the line item "Thermal Barrier Heat Exchanger Piping (Tubing) and Flanges" on page 3.1-8, row 3, to add the Reactor Coolant System Operational Leakage Monitoring Program as an additional AMP to the Chemistry Control Program for managing aging in the thermal barrier heat exchanger piping.
>
> 4. Supplement Table 3.1-1 of the application by modifying the line item "Immersion Heater Sheaths" on page 3.1-9, row to add the Inservice Inspection Program as an additional AMP to the Chemistry Control Program for managing aging in the immersion heater sheaths.

The applicant's responses to potential open item 3.1.1-1 provide a justified reclassification or clarification of the classification for the components identified under the scope of the potential open item. These actions also provide an inspection program that is accepted by the NRC and will be used in addition to the Chemistry Control program to manage loss of material and cracking in these components. Based on these considerations, the staff concludes that the issue is resolved.

On the basis of the evaluations above, with the exception of open item 3.0.3.10.2-1 pertaining to volumetric examination of small-bore piping and open item 3.0.3.10.2-2 pertaining to planned activities in response to the V. C. Summer hot leg crack event, the staff finds that these AMPs are acceptable for managing the pertinent aging effects and providing assurance that the intended function(s) of the RC Class 1 piping and associated components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.1.3 Conclusions

The staff reviewed the information included in Section 3.1.1 of the LRA, as supplemented by the applicant's April 15, 2002 response to the RAI 3.1.1-1. On the basis of its review, with the exception of open item 3.0.3.10.2-1 pertaining to volumetric examination of small-bore piping and open item 3.0.3.10.2-2 pertaining to planned activities in response to the V. C. Summer hot leg crack event, the staff concludes that the applicant has demonstrated that the aging effects associated with the RC Class 1 piping and associated components will be adequately managed so that there is reasonable assurance that these components will perform their intended function(s) consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2 Pressurizers

The McGuire and Catawba reactor units each have one pressurizer connected to the RCS hot leg piping via the surge line and the cold leg piping via the spray line. The pressurizers are vertical, cylindrical vessels with hemispherical top and bottom heads. The spray line and surge line nozzles are provided with thermal sleeves to minimize thermal stresses in the line nozzles. Access to the pressurizers is provided through manway openings near the top of the pressurizers. During normal operation, the pressurizers contain a combination of borated reactor coolant and steam that is maintained at the desired temperature and pressure by the electric heaters and pressurizer spray system. The chemical and volume control system maintains the desired water level in the pressurizer during steady-state operation. Section 2.3.1.3 of the LRA, Section 5.4.10 of the Catawba UFSAR, and Section 5.5.10 of the McGuire UFSAR give a general description of the Westinghouse pressurizers at Duke plants, which are designed in accordance with the ASME Code, Section III.

The pressurizers are designed to accommodate insurges and outsurges caused by the power load transients. During an insurge, the spray system condenses steam to prevent the pressure reaching the operating point of the power-operated relief valve. A continuous spray flow is provided to ensure that the water chemistry within the pressurizer is consistent with that in the RCS. During an outsurge, water flashes to steam due to the resulting pressure reduction and the automatic actuation of the heaters to keep the pressure above the minimum allowable limit. The design functions of the pressurizers are to maintain the structural integrity of the reactor coolant pressure boundary during steady-state operation and normal heatup and cooldown, and to limit pressure changes, to an allowable range, that are caused by reactor coolant thermal expansion and contraction during normal plant load changes.

3.1.2.1 Technical Information in the Application

The applicant described its AMR of the pressurizer sub-components for license renewal in Section 3.1.1 of the LRA, "Aging Management Review Results Tables," as supplemented by the applicant's responses to RAI 3.1.2-1, 3.1.2-2, 3.1.2-3, and 2.3.2.7-1, dated April 15, 2002. The staff reviewed this section of the LRA to determine whether the applicant had demonstrated that the effects of aging on the pressurizers will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The shell, lower and upper heads and manway are fabricated from carbon steel and low alloy steel, and are clad with austenitic stainless steel on all internal surfaces exposed to the reactor coolant. This provides corrosion resistance to the borated reactor coolant. The support skirt and flange are fabricated from carbon steel. The material for the surge, spray, relief, and safety nozzles is low alloy steel clad with stainless steel. As indicated in Westinghouse WCAP-14574-A, “License Renewal Evaluation: Aging Management Evaluation for Pressurizers,” Duke pressurizer safe ends are constructed from stainless steel and welded to the nozzles with Inconel 82/182. The nozzles are buttered with Inconel 182 and post-weld heat treated (PWHT). Then the safe ends are welded to the buttering with Inconel 82/182 with no subsequent PWHT. The heater well nozzles are stainless steel forged penetrations through which the immersion heaters are installed. The instrument nozzles are fabricated assemblies made from a stainless steel tube and a stainless steel forged coupling for interfacing with the connecting piping. In the applicant’s response to RAI 2.3.2.7-1, dated April 15, 2002, the applicant added the pressurizer spray nozzle head to the scope of license renewal for the McGuire and Catawba nuclear units. The spray nozzle is fabricated from cast austenitic stainless steel (CASS) and is exposed to internal and external borated water environments.

The internal environments include borated water and steam at a maximum pressure of 17.13 MPa (2485 psig) and a maximum temperature of 360 ^{o}C (680 ^{o}F). The external environments include air as well as borated water at coolant leakage locations in the pressurizer.

3.1.2.1.1 Aging Effects

In Table 3.1-2 of the LRA, the applicant identifies that the following aging effects are applicable to the pressurizer sub-components that require aging management:

- cracking
- loss of material
- loss of preload

In the applicant’s response to RAI 2.3.2.7-1, the applicant added cracking as an applicable aging effect for the CASS pressurizer spray heads brought within the scope of license renewal by the applicant.

3.1.2.1.2 Aging Management Programs

The applicant identified existing programs for managing aging effects for the pressurizer sub-components during the license renewal term. The following existing AMPs are identified in the application:

- Chemistry Control program
- Fluid Leak Management program
- ISI Plan
- Alloy 600 Aging Management Review

In the applicant’s response to RAI 2.3.2.7-1, the applicant proposed two programs to manage cracking in the CASS pressurizer spray heads brought within the scope of license renewal: (1) the chemistry control program and (2) a new program, the Pressurizer Spray Head Examination.

The applicant concluded that these AMPs will manage the effects of aging such that the intended function of the pressurizer sub-components will be maintained consistent with the CLB under all design loading conditions throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

The applicant did not specifically identify any TLAA in Section 3.1.1 of the LRA that is applicable to pressurizer sub-components. However, Section 4.0 of the LRA identifies a TLAA to address metal fatigue for ASME Class 1 components, which applies to pressurizer sub-components.

3.1.2.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Sections 3.1.1 and 3.1.2, and in Table 3.1-1 of the LRA and pertinent sections of Appendices A and B to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended function(s) of the pressurizer components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

In Table 3.1-1 of the LRA, the applicant lists the pressurizer sub-components within the scope of the license renewal with their intended functions, material groups, and environment. The table also identifies the aging effects requiring management and the plant-specific AMPs required to manage these aging effects during the period of extended operation. The list of components within the scope of license renewal are grouped in accordance with their component types.

3.1.2.2.1 Aging Effects

In accordance with Section 3.1 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the pressurizer sub-components to provide reasonable assurance that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for Catawba and McGuire. This also included the plant-specific operating experience at both subject plants.

The materials of construction for the pressurizer are stainless steel, low alloy steel, and carbon steel. The pressurizer surge, spray, relief, and safety nozzles are all buttered with nickel-based alloy (Alloy 82/182) weld build up. All surfaces of the pressurizer shells, lower and upper heads, and manways are fabricated from low alloy and carbon steel, and are clad with stainless steel, which provides corrosion resistance to borated water exposure. In Table 3.1-1 of the LRA, the applicant identified the following aging effects associated with pressurizer sub-components that require aging management:

- loss of material and cracking from the interior surfaces of nickel-based pressurizer sub-components that are exposed to a borated water/steam environment
- loss of material and cracking from the interior surfaces of stainless steel pressurizer sub-components in a borated water/steam environment
- cracking and reduction in fracture toughness as applicable aging effect for CASS pressurizer spray heads that are exposed to a borated water/steam environment, as identified the applicant's response to RAI 2.3.2.7-1
- loss of material from the exterior surfaces of carbon steel and low-alloy steel sub-components that could potentially be exposed to borated water leakage environments

- loss of material, cracking and loss of preload of the manway cover alloy steel bolts and studs
- loss of material and cracking in highly-stressed carbon steel and low-alloy steel pressurizer integral attachments (supports) that are exposed to the reactor building environment

Loss of material may occur in pressurizer components under certain conditions. Industry experience demonstrates that exposure to borated water may cause corrosion and lead to a loss of material in carbon or low alloy steel RCS pressure boundary components, including the carbon/low-alloy steel pressurizer shells and heads, the high strength alloy steel bolting materials, the carbon steel support skirt and flange, and the alloy steel integral attachments (supports). NUREG/CR-5576 provides a summary of boric acid wastage events that had occurred in low alloy steel or carbon steel primary pressure boundary components of domestic PWRs through 1990. Since 1990, other significant boric acid wastage events have occurred in the industry, including the boric acid wastage event of the Davis Besse reactor vessel head that was reported in March of 2002. To be consistent with this industry experience, the applicant has appropriately identified that loss of material is an applicable aging effect for the exterior surfaces of carbon or low alloy steel pressurizer components that could be subjected to potential borated water leakage from the pressurizer. The interior surfaces of the carbon steel/alloy steel portions of the McGuire and Catawba pressurizer shells and heads are not exposed to the borated water/steam environment (i.e., they are clad with austenitic stainless steel to prevent exposure to the coolant) and therefore are not subject to boric-acid-induced loss of material in this manner. The applicant’s identification that loss of material is an applicable effect for pressurizer components made from carbon or low-alloy steel is acceptable because it agrees with the staff’s determination in NUREG/CR-5576 that loss of material resulting from postulated leakage of the primary coolant (i.e., postulated borated water leakage) is an applicable aging effect for PWR RCS components made from carbon steel or low alloy steel.

Crevice corrosion and pitting corrosion are mechanisms that may lead to a loss of material of stainless steel or stainless steel-clad components that are under creviced borated conditions and that require aging management for stainless steel in borated water. In WCAP-14574-A, “License Renewal Evaluation: Aging Management Evaluation for Pressurizers,” the Westinghouse Owners Group (WOG) concluded that loss of material from stainless steel or stainless-steel-clad pressurizer components was not an applicable effect for Westinghouse PWRs due to the implementation of hydrogen water chemistry used to minimize the levels of dissolved oxygen in the primary coolant (i.e., borated water). In its safety evaluation on WCAP-14574-A, the staff concluded that the potential to develop crevice corrosion and pitting corrosion would be minimized if an applicant for renewal would confirm that it was implementing hydrogen water chemistry practices at its facilities. The applicant identified that it uses the chemistry control program and hydrogen injection to maintain the hydrogen concentrations in the reactor coolant within specific limits and to minimize the levels of dissolved oxygen in the coolant which otherwise could create environments conducive to the loss of material by crevice corrosion or stress corrosion cracking. For conservatism, however, the applicant has identified loss of material as an applicable aging effect for pressurizer components that are clad with stainless steel and for stainless steel pressurizer components that may have creviced areas and are exposed to the borated reactor coolant (e.g., heater immersion sheaths or stainless steel sleeves in pressurizer nozzle, etc.). This is acceptable to the staff because the applicant has identified loss of material as an applicable effect for stainless steel nickel-based alloy pressurizer components that may be exposed to the borated coolant under creviced conditions and has taken a conservative approach relative to the staff's assessment in its SE on WCAP-14574-A.

Cracking of the pressurizer components may be induced by two primary aging mechanisms: thermal fatigue and stress corrosion cracking. Thermal fatigue is a phenomena that may lead to cracking due to thermal-cyclical loading conditions. The applicant has appropriately identified that the pressurizer support skirt and flange, upper and lower heads, relief nozzle, safety nozzle, shell, spray nozzle, surge nozzle, instrument nozzle, manway and manway bolts/studs, immersion heater, seismic support lugs, and valve support bracket lugs are all susceptible to fatigue-related cracking. The applicant's thermal-fatigue analysis for these pressurizer components is provided in LRA Section 4.3; the staff's evaluation is documented in Section 4.3 of this SER.

Pressurizer components made from austenitic stainless steel or nickel-based alloys, mainly the pressurizer cladding, nozzles and thermal sleeves, are susceptible to SCC in the presence of borated water or steam. In Section 3.1 of the LRA, the applicant did not specifically address whether the potential exists for existing cracks in the pressurizer cladding or associated weldments to grow (as a result of thermal-fatigue induced crack growth) through the cladding and into the ferritic portions of the pressurizer sub-components that the cladding is joined to. The staff is concerned that intergranular stress corrosion cracking (IGSCC) in the heat-affected zones of 304 stainless steel supports that are welded to the pressurizer cladding, could grow as a result of thermal fatigue into the adjacent pressure boundary during the license renewal term. For the issue regarding whether IGSCC could initiate in the cladding weldments, the staff considers that these weldments would not require aging management in the period of extended operation if an applicant could provide reasonable justification that sensitization has not occurred in these welds during the fabrication of these components.

By letter dated January 28, 2002, the staff requested, in RAI 3.1.2-1, the applicant to discuss whether thermal fatigue-induced crack initiation and growth is an issue for the ferritic pressurizer components that are clad austenitic stainless steel, and specifically whether thermal-fatigue-induced growth of an existing crack into the ferritic base material beneath the clad or into the welds joining the cladding to the pressurizer base metals is an applicable effect that requires aging management. In its response dated April 15, 2002, the applicant stated that, while the cladding and the welds that attach internal items to the pressurizer cladding may be sensitized, the location that is most likely to experience cracking by thermal fatigue is the welded joint that connects the surge nozzle to the pressurizer shell. The applicant also stated that, if cracking were to occur at the surface of the surge nozzle cladding and propagate into the base metal, volumetric examinations of the cladding performed in accordance with ASME Section XI, Examination Category B-D, would detect the flaw prior to loss of the pressurizer intended function. Based on the fatigue usage factors for the pressurizer shell and its nozzles, the staff considers this location to be the most limiting location for thermal-fatigue-induced crack growth. The staff concludes that the applicant's implementation of volumetric examinations of this location will be sufficient to identify whether thermal-fatigue-induced crack growth is an issue for the ferritic pressurizer components that are clad with stainless steel. The staff therefore considers RAI 3.1.2-1 to be resolved.

By letter dated January 28, 2002, the staff requested, in RAI 3.1.2-2, the applicant to discuss how the implementation of plant-specific procedures and quality assurance requirements, if any, for the welding and testing of austenitic stainless steel provides reasonable assurance that sensitization and cracking had not occurred in the pressurizer cladding welds. In its response dated April 15, 2002, the applicant stated that the possibility that sensitized areas exist in the 304 stainless steel supports or their welds cannot be precluded even with controlled material selection and the implementation of manufacturing processes that minimize sensitization, and that the Chemistry Control program, which precludes stress corrosion cracking in other pressurized water reactor primary system materials, is also effective in preventing stress corrosion cracking in these pressurizer components and welds. The applicant also stated that rigorous control of oxygen and chlorides provides a benign environment that has been shown to be effective both in laboratory experiments and years of operating experience.

The applicant’s response to RAI 3.1.2-2 proposes to use an acceptable mitigation strategy (i.e., the Chemistry Control program) as the basis for precluding crack initiation by stress corrosion in the pressurizer cladding. When taken in context with the applicant’s response to RAI 3.1.2-1, the applicant also proposes to inspect the locations in the McGuire and Catawba units that are most likely to experience cracking by thermal fatigue consistent with volumetric examinations performed in accordance with ASME Section XI Category B-D. For the McGuire/Catawba units, this is the weld that joins the surge nozzle and its cladding to the pressurizer shell. This inspection also will provide the applicant with an indication whether stress corrosion cracking has occurred in the pressurizer cladding. Therefore, the staff finds that the applicant’s responses to RAIs 3.1.2-1 and 3.1.2-2, when taken together in context, resolve these RAIs because the issue of whether stress corrosion cracking is an issue for the pressurizer cladding will be determined by the applicant using the volumetric inspection technique.

In addition, the applicant stated in LRA Table 3.1-1 that cracking is an applicable effect for the surfaces of stainless steel or nickel-based pressurizer components (including the cladding for alloy steel pressurizer component clad with austenitic stainless steel) that are exposed to the borated water/steam environment. The staff finds the applicant’s assessment of cracking for these stainless steel or nickel-based alloy pressurizer components is acceptable because: (1) the applicant has appropriately identified cracking as an applicable effect for stainless steel and nickel-based pressurizer components, and (2) the applicant has addressed the issue of growth of pre-existing cracks through the cladding into the ferritic (i.e., carbon steel or alloy steel) base metals of the pressurizer.

Stress-induced cracking may occur in the surfaces of high-strength (> 150 ksi yield strength) alloy steel bolting materials (including nut, studs, and washers) and in alloy or carbon steel integral attachments that are under loaded (stressed) conditions and are exposed to the reactor building environment. In its safety evaluation on WCAP-14574-A, dated October 26, 2002, the staff concluded that the potential to develop SCC in alloy steel manway bolts will be minimized if the yield strength of the material is held to less than 150 ksi, or the hardness is less than 32 on the Rockwell C hardness scale. In lieu of providing documentation that the yield strengths or Rockwell C hardness values for the bolting materials would conform to acceptable values provided in the staff’s safety evaluation on WCAP-14574-A, the applicant has identified cracking as an applicable aging effect for the alloy steel pressurizer bolting materials that are exposed to the reactor building environment. The applicant similarly identified cracking as an applicable effect for the exterior surfaces of highly stressed alloy steel and carbon steel pressurizer supports that are exposed to the reactor building environments. The applicant’s identification of cracking as an applicable effect for these components is conservative relative to the staff's safety evaluation on WCAP-14574-A and is therefore acceptable to the staff.

Bolted connections in plant systems may also be subject to a loss of preload (loss of mechanical closure integrity) due to the stress relaxation. The applicant has also identified in Table 3.1-1 of the application that loss of preload is one of the three applicable aging effects for the manway cover bolts/studs. The applicant's identification that loss of preload is an applicable effect for the manway cover bolts and studs is acceptable because it is in agreement with Table 3.1-1 of NUREG-1800, which identifies loss of preload due to stress relaxation as an applicable aging effect for bolted manway covers in the RCS.

In its April 15, 2002, response to RAI 2.3.2.7-1, which pertained to the staff's scoping and screening evaluation that is documented in Section 2.3.2.7 of the SER, the applicant added the pressurizer spray nozzle heads to the scope of license renewal for the McGuire and Catawba pressurizers. The pressurizer spray head serves a safety function of pressure control for the RCS but does not serve a pressure boundary function for the RCS. The spray nozzle is fabricated from CASS and is exposed to internal and external borated water environments. In the response to RAI 2.3.2.7-1, the applicant identified that cracking was an applicable effect for the CASS pressurizer spray nozzles. In the McGuire/Catawba application both loss of material and cracking are applicable effects for other CASS components of the RCS that serve a pressure boundary function and that are exposed to borated water conditions. The staff concludes that loss of material will not significantly effect the spray pattern from the pressurizer spray heads to a point where the spray heads would not be capable of performing their safety function of providing pressure control for the RCS because the McGuire and Catawba pressurizer spray head designs do not use a perforated bottom plate to accomplish the spray function. Loss of material in the spray heads will not, in this case, lead to a loss or significant change in the spray distribution when the pressurizers are called upon to perform their spray functions. Based on this determination, and since this conforms to Table 3.1-1 of NUREG-1800, the staff concludes that only cracking need be identified as an applicable effect for the CASS pressurizer spray heads within the scope of license renewal, and that the applicant's resolution of RAI 2.3.2.7-1 is acceptable.

On the basis of the description of the internal and external environments, materials used, and the applicant's review of industry and plant-specific experience, the staff concludes that the applicant has identified all aging effects that are applicable for the pressurizer sub-components.

3.1.2.2.2 Aging Management Programs

The applicant identified the following existing programs for managing aging effects identified in Table 3.1-1 as being applicable to the pressurizer sub-components:

- Chemistry Control program
- Fluid Leak Management program
- ISI Plan
- Alloy 600 Aging Management Review

The Chemistry Control program (Section B.3.6 of Appendix B to the LRA) provides water quality that is compatible with the materials of construction used for the McGuire and Catawba pressurizer components in order to minimize loss of material and cracking. This program is developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the pressurizer sub-components. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

The Fluid Leak Management program (Section B.3.15 of Appendix B to the LRA) was developed by the applicant in response to NRC Generic Letter 88-05. Inspections are performed to provide reasonable assurance that borated water leakage from the reactor coolant pressure boundary does not lead to undetected loss of material on the external surface of RC piping and associated components, and specifically for those made out of carbon steel or low alloy steel. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the pressurizer sub-components. The staff's evaluation of this AMP is documented in Section 3.0.

For the pressurizer components, the ISI Plan (Section B.3.20 of Appendix B to the LRA) manages aging effects of loss of material, cracking, and gross loss of preload. The scope of the ISI plan for Class 1 components complies with the requirements of ASME Section XI, Subsection IWB. Depending on the examination category, the methods of inspections may include visual, surface and/or volumetric examination of weld locations susceptible to aging degradation. The examination methods required by Subsection IWB for implementation either directly inspect for loss of material and cracking in the Class 1 components and are capable of detecting the aging effects, or inspect for indications of reactor coolant leakage which, in the case of bolted connections, would be indicative of a loss of preload in the bolt. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the pressurizer. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

By letter dated January 28, 2002, the staff requested, in RAI 3.1.2-3, the applicant to clarify how the ISI plan and fluid leak management program are sufficient to manage loss of preload of the pressurizer manway bolts and studs. In its response dated April 15, 2002, the applicant stated that the aging effect "loss of preload" that is identified for the pressurizer manway bolts/studs would manifest itself as leakage due to the loss of mechanical closure integrity and that, if there was a loss of mechanical closure integrity, the leakage would be detected by the Fluid Leak Management program. The pressurizer pressure retaining components, including all bolted closures, are also visually inspected for leakage by the ISI Plan. The applicant's response to RAI 3.1.2-3 provides a valid basis of how the ISI Plan and Fluid Leak Management program will be used to manage loss of preload in the bolts and studs. The staff concludes that the applicant's response resolves RAI 3.1.2-3. The applicant's basis for using the Fluid Leak Management program and ISI Plan as the programs for managing loss of preload in the pressurizer manway bolts and studs is acceptable because both of the programs have acceptable inspection-based means of determining whether loosening of the bolted connections in the pressurizer manway covers has occurred.

The Alloy 600 Aging Management Review is presented in Section B.3.1 of Appendix B to the LRA. The review will be used to determine whether the applicant should augment or change the inspection activities currently proposed to manage cracking in ASME Code Class 1 Alloy 600/690, Alloy 82/182, and Alloy 52/152 locations in the RCS. In response to RAI 2.3.2.7-1, the applicant also proposed to implement a new aging management program, the "Pressurizer Spray Head Examination," to manage the aging effects that the applicant had identified in its response to the RAI as being applicable to the pressurizer spray head. The staff's evaluation of the Alloy 600 Aging Management Review and the Pressurizer Spray Head Examination follows:

<u>Alloy 600 Aging Management Review</u>

The applicant described its Alloy 600 Aging Management Review in Section 3.1 of Appendix B of the LRA. The staff reviewed the application to determine whether the applicant had demonstrated that the Alloy 600 Aging Management Review will adequately manage the applicable effects of aging in the plants during the period of extended operation as required by 10 CFR 54.21(a)(3).

The objective of the applicant's Alloy 600 Aging Management Review (A600 AMR) is to provide general oversight and management of primary water stress corrosion cracking (PWSCC) in nickel-based alloy (Alloy 600) components within the scope of license renewal and to ensure that nickel-based alloy locations are adequately inspected by the ISI Plan (Section B.3.20 of Appendix B to the LRA) or other existing programs such as the Control Rod Drive Mechanism and Other Vessel Head Penetration Program (Section B.3.9 of Appendix B to the LRA), the Reactor Vessel Internals Inspection Program (Section B.3.27 of Appendix B to the LRA), and the Steam Generator Integrity Program (Section B.3.31 of Appendix B to the LRA).

The applicant stated that the A600 AMR will identify Alloy 600/690, 82/182 and 52/152 locations. A ranking of susceptibility to primary water stress corrosion cracking (PWSCC) will be performed for the nickel-based alloy locations. The applicant indicated that it will perform a review to ensure that nickel-based alloy locations are adequately inspected by the ISI Plan or other existing programs such as the Control Rod Drive Mechanism and Other Vessel Head Penetration Program, the Reactor Vessel Internals Inspection Program, or the Steam Generator Integrity Program. This applicant's review will utilize industry and Duke-specific operating experience. The inspection method and frequency of inspection for the Alloy 600/690, 82/182, and 52/152 locations for the period of extended operation will be adjusted as needed based on the results of this review. In addition, the applicant will develop supplemental inspection scopes for the period of extended operation as necessary.

For McGuire, the applicant stated that this review will be completed following issuance of the renewed operating licenses for the McGuire Nuclear Station and by June 12, 2021, which corresponds to the end of the initial 40-year license period for McGuire 1. For Catawba, the applicant stated this review will be completed following issuance of the renewed operating licenses for the Catawba Nuclear Station and by December 6, 2024, which corresponds to the end of the initial 40-year license period for Catawba 1. The applicant indicated that the results of these reviews will be incorporated into the unit-specific ISI plans for the ISI intervals during the period of extended operation.

The applicant did not describe the A600 AMR in terms of the specific program attributes that were defined in Section B.2.2 of Appendix B to the McGuire/Catawba applications. The staff therefore could not focus its evaluation of the A600 AMR on the following seven program attributes:

1. Scope of Program
2. Preventative Actions
3. Parameters Monitored or Inspected

4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria
7. Operating Experience

By letter dated January 28, 2002, the staff requested, in RAI B.3.1-1, that the applicant confirm the following aspects of the A600 AMR:

1. The A600 AMR is simply a susceptibility ranking review calculation that will be used to determine whether inspection techniques proposed in aging management programs for managing aging effects in Alloy 600 components of the reactor coolant pressure boundary components (including reactor vessel internal components) should be enhanced or augmented; and

2. The program attributes are normally provided in the application for programs that are listed in the LRA as aging management programs. Since the A600 AMR is simply a review program, the program attributes for the review are not necessary.

In its response dated April 15, 2002, the applicant stated that the staff's description of the A600 AMR is correct. The purpose of the A600 AMR is simply to ensure that nickel-based alloy locations are adequately inspected by either the ISI Plan or other existing programs, such as the Control Rod Drive Mechanism and Other Vessel Head Penetration Program, the Reactor Vessel Internals Inspection Program, and/or Steam Generator Surveillance Program. These aging management programs are described in detail in Sections B.3.20, B.3.9, B.3.27, and B.3.31 of Appendix B to the application, respectively, and evaluated in Sections 3.0.3.9.1, 3.1.3.2.2.1, 3.1.4.2.2.1, and 3.1.5.2.2.1 of this SER, respectively.

The applicant stated that the results of the A600 AMR will be used as an applicant initiative to determine whether a change to the inspection method and frequency of inspection criteria for Alloy 600/690, 82/182, and 52/152 locations is necessary during the periods of extended operation. It needs to be emphasized that the applicant uses inspection criteria in the ISI Plan, the Control Rod Drive Mechanism and Other Vessel Head Penetration Program, the Reactor Vessel Internals Inspection Program, and Steam Generator Surveillance Program as the basis for inspecting Alloy 600 locations in the RCS piping, RV and RV head penetration nozzles, RV internals and SGs. The applicant's Appendix B corrective actions program adequately addresses findings that result from inspections performed in accordance with these inspection programs. The applicant has emphasized that A600 AMR will only to be used as an additional tool for determining whether the requirements in these programs for inspecting the Alloy 600 locations of the McGuire and Catawba nuclear plants need to be augmented. Since the corrective actions program is already in effect at the McGuire and Catawba stations, and since implementation of the corrective actions program will provide the applicant with a basis for augmenting the inspection requirements for RCS Alloy 600 locations should cracking or loss of material be detected, the staff finds that the A600 AMR is an acceptable tool for augmenting the inspection requirements in the ISI Plan, the Control Rod Drive Mechanism and Other Vessel Head Penetration Program, the Reactor Vessel Internals Inspection Program, and the Steam Generator Surveillance Program.

FSAR Supplement: The applicant's FSAR Supplement for the A600 AMR is provided in Section 18.2.1 of Appendix A of the LRA, and provides an overview of the review as described in

Section B.3.1 of Appendix B of the LRA. Based on the applicant's response to the staff's request for additional information, as documented in the letter dated April 15, 2002, the FSAR supplement for the A600 AMR is acceptable.

The staff reviewed the information provided in Section 3.1 of Appendix B of the LRA. In addition, the staff considered the applicant's responses to the staff's RAIs provided in a letter to the NRC dated April 15, 2002. The applicant's current description of the A600 AMR provides a sufficient basis as to how the review will be used to determine whether the inspection frequencies, methods and criteria specified in the ISI Plan for inspecting Alloy 600/690, 82/182, and 52/152 locations or in other existing programs, such as the Control Rod Drive Mechanism and Other Vessel Head Penetration Program, the Reactor Vessel Internals Inspection Program, and the Steam Generator Integrity Program, need to be augmented or enhanced. The staff's evaluation of these programs is given in Sections 3.0.3.9.1, 3.1.3.2.2.1, 3.1.4.2.2.1, and 3.1.5.2.2.1 of this SER, respectively. The staff's assessment of the Control Rod Drive Mechanism and Other Vessel Head Penetration Program, as given in Section 3.1.3.2.2.1 of this SER, addresses the implications of the Oconee CRDM nozzle cracking events, the Davis Besse boric acid wastage event, and NRC Bulletins 2001-001 and 2002-01 on the acceptability of the Control Rod Drive Mechanism and Other Vessel Head Penetration Program and on the assurance of the structural integrity of the McGuire/Catawba RV head penetration nozzles during the extended periods of operation for the units. When implemented, the A600 AMR should incorporate the implications of the Davis Besse boric acid wastage event into the review process. Resolution of this current operating issue is being pursued by the staff under 10 CFR Part 50. The outcome of this resolution will dictate the nature and extent to which the A600 AMR will be modified to address this issue.

On the basis of its review, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed by the A600 AMR so that there is reasonable assurance that the intended function(s) of the pressurizer sub-components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

Pressurizer Spray Head Examination

The applicant describes the Pressurizer Spray Head Examination in its April 15, 2002, response to RAI 2.3.2.7-1. In its response, the applicant describes its evaluation of this program in terms of aging management program attributes provided in the Standard Review Plan for license renewal. The applicant credits this program as managing the effects of aging for the pressurizer spray heads for the McGuire and Catawba units.

The staff reviewed the applicant's description of the program to determine whether the applicant had demonstrated that it will adequately manage the applicable effects of aging in selected pressurizer spray heads during the periods of extended operation, as required by 10 CFR 54.21(a)(3).

The purpose of the pressurizer spray head examination is to characterize any cracking in the CASS pressurizer spray heads for the McGuire and Catawba units. The applicant states that it plans to inspect the operating unit with the most hours at operating temperature among the four units at McGuire and Catawba, and that McGuire 1 is expected to be the lead unit for this inspection. The applicant states that, after the results of the McGuire 1 inspection are evaluated, additional examinations may be performed on the pressurizer spray heads at McGuire 2 and Catawba 1 and 2.

The staff evaluated the pressurizer spray head examination, as described in the applicant's response to RAI 2.3.2.7-1, on the following seven program attributes for the program:

1. Scope of Program
2. Preventative Actions
3. Parameters Monitored or Inspected
4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria
7. Operating Experience

The staff's evaluations of these program attributes are given in the paragraphs that follow. The staff's evaluation of the other three program attributes (confirmatory actions, corrective actions, and administrative controls) for the Pressurizer Spray Head Examination is documented in Section 3.0.4 of this SER.

[Scope] The applicant stated that the scope of the Pressurizer Spray Head Examination is the internal spray head of the McGuire and Catawba pressurizers. The examination is a new one-time inspection of the McGuire 1 pressurizer spray head (which will be representative of the other units' pressurizer spray heads) to ensure that cracking of the spray heads will not lead to a loss of pressure control function for these components. The staff's basis for why the McGuire 1 pressurizer spray head is representative of the other units' spray heads is documented in the monitoring and trending section below. The examination is component specific. The applicant's scoping attribute is therefore acceptable to the staff.

[Preventative Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or mitigate aging degradation. Since the pressurizer spray head examination is a one-time inspection program and does not rely on actions to prevent the occurrence of aging effects or to mitigate the degree of aging that can occur, the staff concludes that the applicant's preventative action attribute is acceptable.

[Parameters Monitored or Inspected] The applicant stated that the parameter inspected by the pressurizer spray head examination is cracking of the pressurizer spray head. In Section 3.1.2.2.7 of NUREG-1800, the staff states, in part, the crack initiation and growth due to SCC and PWSCC are applicable effects for pressurizer spray heads. The applicant's parameters monitored or inspected program attribute for the McGuire/Catawba pressurizer spray heads is acceptable because it is a one-time inspection program designed to detect cracking that could result from SCC or PWSCC.

[Detection of Aging Effects] The applicant stated that the Pressurizer Spray Head Examination is a one-time inspection and will detect the presence of cracking in the pressurizer spray heads. The pressurizer spray head examination is one-time inspection designed to detect potential cracks in the spray heads prior to their growing to a size greater than the critical crack size, which is a limiting allowable crack size for the material. This accounts for changes (reductions) in the critical crack size resulting from a loss of fracture toughness induced by thermal aging.

In Section 3.1.2.2.7 of NUREG-1800, the staff recommends that a plant-specific aging management program be proposed to manage crack initiation and unacceptable crack growth in pressurizer spray heads because existing programs may not be capable of mitigating or detecting crack initiation and growth due to SCC. The applicant's detection of aging effects attribute for the McGuire/Catawba pressurizer spray heads is a one-time inspection program designed to meet this recommendation and is therefore acceptable to the staff.

[Monitoring and Trending] The applicant stated that the Pressurizer Spray Head Examination is a visual examination (VT-3) of the pressurizer spray head, and that no actions are taken as part of this program to trend inspection or test results. The applicant stated that, for McGuire 1, this new inspection will be completed following issuance of renewed operating license for McGuire 1 and by June 12, 2021, and that any inspection (if needed, based on the results of the McGuire 1 spray head examination) of the McGuire 2 pressurizer spray head will be completed by March 3, 2023. The applicant stated that, for Catawba, if warranted based on the results of the McGuire 1 examination, the new inspections will be completed following the issuance of the renewed operating licenses for the Catawba 1 and 2 and by December 6, 2024, for Catawba 1, and February 24, 2026, for Catawba 2. The program is designed to perform a one-time visual inspection of the McGuire 1 pressurizer spray head to ensure that cracks will be detected prior to reaching the critical crack size for the CASS materials used to fabricate the spray heads. The applicant will evaluate the results of pressurizer spray head examination performed at McGuire 1 and will use them as the basis for determining whether additional pressurizer spray head examinations are warranted for McGuire 2 and Catawba 1 and 2. The applicant evaluated whether the CASS materials in the pressurizer spray heads are susceptible to thermal aging and applied the methods in the staff's Interim Safety Guidance on CASS[2] as an acceptable basis for concluding that loss of fracture toughness was not an applicable aging for the McGuire and Catawba pressurizer spray heads. Since the McGuire and Catawba pressurizer spray heads are not susceptible to thermal aging, the CASS materials used to fabricated the spray heads are considered to be tough, fracture-resistant materials, and any cracking in the pressurizer spray head is therefore considered to be a slow-acting mechanism. The staff therefore expects minimal cracking, if any, in the spray heads. Based on these considerations, the staff concludes use of a one-time inspection of the pressurizer spray head at McGuire 1 will be acceptable for detecting cracking in the spray heads for the other three units prior to their failure and for determining whether additional inspections of the pressurizer spray heads at McGuire 2 and at Catawba 1 and 2 are warranted. However, the staff's position is that VT-3 examinations may not be capable of detecting cracks that may occur in the pressurizer spray head. The staff therefore requests that the applicant amend the Pressurizer Spray Head Examination to state that VT-1 examination methods, which are capable of detecting and resolving cracks in the pressurizer spray heads, will be used for the one-time inspection. This is characterized as open item 3.1.2.2.2-1. The scope of open item 3.1.2.2.2-1 includes the potential need to revise the acceptance criteria element and the FSAR Supplement.

[Acceptance Criteria] The applicant stated that the acceptance criterion for the pressurizer spray head examination will be in accordance with those for ASME Section XI, VT-3 examinations. Surface-breaking cracks detected by these visual examinations are required by

2 Letter from C. I. Grimes (NRC) to D. J. Walters (NEI), *License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components,* Project No. 690, dated May 2000.

10 CFR 50.55a, “Code and Standards,” to be evaluated against corresponding flaw evaluation criteria that are provided in an acceptable edition of Section XI, ASME Boiler and Pressure Vessel Code, as endorsed by the rule. The applicant will assess any cracks detected by the examination against the flaw evaluation criteria for surface breaking flaws in the 1989 Edition of Section XI to the ASME Boiler and Pressure Vessel Code. This is an acceptable edition of Section XI endorsed by reference in 10 CFR 50.55a. The staff identified open item 3.1.2.2.2-1 pertaining to the applicant’s proposed use of VT-3 rather than VT-1 examination technique. Therefore, the applicant should apply VT-1 examination acceptance criteria from an accepted edition of the ASME Section XI code to evaluate any surface-breaking flaws that might be detected as a result of the VT-1 examination.

[Operating Experience] The applicant stated that the Pressurizer Spray Head Examination is a newly proposed, one-time inspection for the McGuire and Catawba pressurizer spray heads, and that there is not any operating experience that is pertinent to the evaluation of the McGuire and Catawba pressurizer spray heads at this time. This is acceptable since the results from examination of the pressurizer spray head at McGuire 1 will provide the LRA-specific experience that will be used to determine whether additional examinations are warranted for the pressurizer spray heads at McGuire 2 and Catawba 1 and 2.

FSAR Supplement: The Pressurizer Spray Head Examination is a new aging management program proposed by the applicant to manage the aging effects in the CASS spray heads for the McGuire and Catawba pressurizers. The Pressurizer Spray Head Examination was not originally described in Chapter 18 of the FSAR Supplements for the McGuire and Catawba Nuclear Stations. By letter dated April 15, 2002, in response to RAI 2.3.2.7-1, the applicant amended the application and provided its FSAR Supplement description for the Pressurizer Spray Head Examination. The applicant’s FSAR Supplement description for this examination is identical to the applicant’s program attributes for the examination, as provided in the response to the RAI. Therefore, revision of the FSAR Supplement may be warranted to reflect resolution of open item 3.1.2.2.2-1. The scope of open item 3.1.2-1 includes the potential need to revise the FSAR Supplement.

In conclusion, the applicant has proposed in its response to RAI 2.3.2.7-1 to implement a one-time inspection program, the Pressurizer Spray Head Examination, for the McGuire and Catawba pressurizer spray heads. Based on the staff’s evaluation of the program attributes for the Pressurizer Spray Head Examination, as described in the applicant’s response to RAI 2.3.2.7-1 and evaluated in the paragraphs above, with the exception of open item 3.1.2.2.2-1, the staff concludes that the Pressurizer Spray Head Examination for the McGuire and Catawba pressurizers will be sufficient to detect cracking of the spray head prior to failure of the components and to maintain the pressure control function of the spray heads during the periods of extended operation for the units.

On the basis of its review, with the exception of open item 3.1.2.2.2-1, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed by the Pressurizer Spray Head Examination so that there is reasonable assurance that the intended function(s) of the pressurizer sub-components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3 Conclusions

The staff reviewed the information included in Section 3.1.1 of the LRA, as supplemented by the applicant's April 15, 2002, responses to the RAIs 2.3.2.7-1, 3.1.2-1, 3.1.2-2, 3.1.2-3, and B.3.1-1. On the basis of its review, with the exception of open item 3.1.2.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the pressurizer sub-components will be adequately managed so that there is reasonable assurance that these sub-components will perform their intended functions consistent with the CLB for the McGuire and Catawba reactor units throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.3 Reactor Vessel and Control Rod Drive Mechanism Pressure Boundary

The four reactor vessels (RVs) at McGuire and Catawba are cylindrical shells with welded hemispherical lower heads and flanged, gasketed hemispherical upper heads. Each vessel contains the core, core supporting structures, control rods and parts directly associated with the core. The upper head contains 82 penetrations (78 for control rod drive mechanism (CRDM) penetrations and 4 auxiliary head adapters). Each vessel has an inlet nozzle and an outlet nozzle for each of the four primary piping loops located just below the flange. Coolant enters through the inlet nozzles, flows down the core barrel-vessel wall annulus, turns at the bottom and flows through the core to the outlet nozzles.

The bottom head has 58 penetrations for connection and entry of in-core instrumentation. Each penetration consists of a tubular member made from Inconel, which is attached to the lower head by a partial penetration weld. Stainless steel conduits extend from the Inconel tubes down through the concrete shield area and up to a thimble seal table. The retractable thimble tubes, which travel within the conduit, are closed at the leading end, are dry inside, and serve as the pressure barrier between the reactor water pressure and the reactor building atmosphere. Mechanical seals between the thimbles and the conduits are provided at the seal table.

The reactor vessel is classified as Safety Class 1 and therefore, the design and fabrication of the vessel was carried out in accordance with ASME Code, Section III, Class 1 requirements. The use of sensitized stainless steel as a pressure boundary material was eliminated by either a choice of material or by programming the method of assembly. The carbon/low-alloy steel vessels are clad on their internal surfaces with austenitic stainless steel to prevent the carbon/low-alloy steel materials from being in direct contact with primary coolant.

For Catawba 1 and McGuire 2, the cylindrical portions of the RVs and the beltline nozzles are made from forgings; for McGuire 1 and Catawba 2, the cylindrical portions of the RVs and the beltline nozzles are made up of several shells, each consisting of formed plates joined by full penetration, longitudinal and circumferential weld seams. The hemispherical heads are made from dished plates. The vessel plates or forgings are joined by welding, using the single or multiple wire submerged arc and the shielded metal arc processes.

Section 2.3.1.4 of the LRA, UFSAR Section 5.4 for McGuire, and UFSAR Section 5.3 for Catawba describe the reactor vessel and its appurtenances.

3.1.3.1 Technical Information in the Application

The applicant described its AMR of the RV and CRDM pressure boundary components for license renewal in Section 3.1.1 of the LRA, "Aging Management Review Results Tables," as supplemented by the applicant's April 15, 2002, response to the RAI. The staff reviewed this section of the LRA to determine whether the applicant had demonstrated that the effects of aging on the RV and CRDM pressure boundary components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Nineteen component types are listed in Table 3.1-1 of the LRA. They include shell components, nozzles, and several vessel penetration components including the CRDM housings, instrumentation tubes and their sub-components. Seventeen of these components provide the pressure boundary function. The core support pads provide the support function for the RV internals and the RV integral attachments provide the component support to the RV.

3.1.3.1.1 Aging Effects

Table 3.1-1 includes the materials of construction of the components, the service environment that they are exposed to, the aging effects that act on the components, and the AMPs that will be used to manage the aging effects during the period of extended operation. The service environment listed in the table for the RV and CRDM pressure boundary components is borated water. The environment for the RV integral attachments, the RV head closure studs and the external surfaces of the RV is the reactor building atmosphere. The table lists the following aging effects that require management during the period of extended operation:

- cracking
- loss of material
- reduction of fracture toughness
- loss of preload.

3.1.3.1.2 Aging Management Programs

The applicant identified existing programs for managing the aging effects for the RV and CRDM pressure boundary components during the license renewal term. The following existing AMPs are identified in the application:

- Chemistry Control program
- Fluid Leak Management program
- ISI Plan
- Alloy 600 Aging Management Review
- Reactor Vessel Integrity program
- CRDM Nozzle and Other Vessel Closure Penetrations Inspection program
- RCS Operational Leakage Monitoring program
- Bottom-Mounted Instrumentation Thimble Tube Inspection program

The applicant concluded that these AMPs will manage the effects of aging such that the intended function of the RV and CRDM pressure boundary components will be maintained consistent with the CLB under all design loading conditions throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

The applicant did not specifically identify any TLAA in Section 3.1.1 of the LRA that is applicable to RV and CRDM pressure boundary components. However, Section 4.0 of the LRA includes the following TLAAs applicable to RV and CRDM pressure boundary components:

- reactor vessel neutron embrittlement (Section 4.2 of the application)
- metal fatigue for ASME Class 1 components (Section 4.3 of the application)

The staff's evaluations of these TLAAs are given in Sections 4.2 and 4.3 of this SER.

3.1.3.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Sections 3.1.1 and 3.1.2, and in Table 3.1-1, of the LRA and pertinent sections of Appendices A and B to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended function(s) of the RV and CRDM pressure boundary components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

The reactor vessel closure region (i.e., flanged upper head) is sealed by two hollow metallic O-rings. Seal leakage is detected by means of two leakoff communications; one between the inner and outer ring and one outside the outer O-ring. These leak-off lines are within the scope of license renewal are addressed as one of the non-Class 1 RCS components within the scope of LRA Table 3.3-41, "Aging Management Review Results - Reactor Coolant System (Non Class-1 Components)." The staff's evaluation of the applicant's AMRs for the RCS leak-off lines is documented in Section 3.3.32 of this SER.

3.1.3.2.1 Aging Effects

In accordance with Section 3.1 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the RV and CRDM pressure boundary components to provide reasonable assurance that the aging effects that require management for specific material-environment combinations are the only aging effects of concern for the Catawba and McGuire RV and CRDM components. This also included the plant-specific operating experience at both subject plants.

The effects of aging associated with RV and CRDM pressure boundary components requiring aging management are:

- loss of material and cracking for internal surfaces of alloy steel, stainless steel, and nickel-based alloy RV/CRDM components exposed to borated water conditions
- reduction of fracture toughness for the alloy steel base-metal and weld materials in the intermediate and lower shells of the McGuire and Catawba RVs
- loss of material from the external surfaces of carbon or alloy steel RV components that are exposed to the reactor building environment and could potentially be exposed to borated water leakage
- loss of material, cracking and loss of preload as applicable aging effects for the RV closure studs, nuts, and washers
- loss of material and cracking for external surfaces of carbon and alloy steel integral attachments to the RV that are exposed to the reactor building environment

Loss of material and cracking are caused by aggressive service environments including corrosive species, low pH, and elevated temperatures. To mitigate these effects, reactor water coolant chemistry and pH are strictly controlled within prescribed limits during plant operation and shutdown. The RV and CRDM pressure boundary components may be subject to loss of material and cracking under certain conditions.

Loss of material may occur in the RV and CRDM pressure boundary components under certain conditions. Carbon steel and low-alloy steel components may be susceptible to general-corrosion-induced loss of material under wet or damp conditions. Industry experience also demonstrates that potential borated water leakage from the RCS pressure boundary may corrode away and lead to a loss of material in carbon or low-alloy steel RCS pressure boundary components. NUREG/CR-5576 provides a summary of boric acid wastage events that had occurred in primary alloy or carbon steel pressure boundary components of domestic PWRs through 1990. The applicant has identified that loss material is an applicable effect for the exterior surfaces of carbon or low alloy steel RV components that could be subjected to potential borated water leakage from the pressurizer. Therefore, the following carbon or low-alloy steel RV components may be susceptible to loss of material: (1) RV steel shells, flanges, rings, bottom heads, and upper closure heads, (2) high strength alloy steel bolting materials, and (3) alloy steel integral attachments (supports). The interior surfaces of the carbon steel/alloy steel portions of the McGuire and Catawba RV shells and heads are not exposed to the borated water/steam environment (i.e., they are clad with austenitic stainless steel to prevent exposure to the coolant) and therefore are not subject to boric-acid-induced loss of material in this manner.

Loss of material may also occur in stainless steel or nickel-based alloy components if the components are exposed to wet creviced conditions or if the components are subject to wear. Loss of material may occur in the RV thimble tubes and CRDM housing flange bolting materials as a result of wear. The applicant has appropriately identified loss of material as being applicable to stainless steel and nickel-based alloy RV components that may be exposed to borated water under creviced conditions (i.e., RV clad components, or CRDM/RV head nozzles/housings), or are subject to wear (i.e., in the RV thimble tubes or CRDM housing flange bolting). The applicant has also conservatively listed loss of material as an applicable aging effect for the RV inlet and outlet nozzle safe-ends at McGuire and Catawba. The applicant's identification of loss of material as an applicable effect for the McGuire and Catawba RV components is acceptable because it conservatively accounts for the potential for the RV components made from carbon steel/alloy steel, stainless steel, or nickel-based alloys to lose material either by boric acid corrosion, crevice corrosion, or wear.

The potential for cracking to occur in carbon or low-alloy steel RV materials is predominantly a phenomenon of thermal-fatigue. Fatigue is caused by large cyclic changes in stress as a result of pressure and thermal transients during service. PWSCC may initiate in RV and CRDM pressure boundary materials fabricated from nickel-based alloys or austenitic stainless steels as a result of exposure to the primary coolant in conjunction with the presence of stresses. RV underclad cracking may be an issue for cladding joined to RV forgings fabricated from SA 508, Class 2 steels (i.e., cracking in the forgings directly adjacent to the stainless steel cladding) if the forgings were fabricated to a coarse grain practice and clad by high-heat-input submerged arc processes. The applicant did not consider this to be an applicable aging mechanism that could lead to cracking of the forging materials used to fabricate the McGuire 2 and Catawba 1 RVs since Duke construction-vintage programs for controlling the welding of stainless steel cladding to low-alloy steel components were consistent with guidelines of NRC Regulatory Guides 1.43 and 1.44. The applicant did, however, identify cracking as a potential applicable effect for low-alloy steel RV shells, RV heads, and RV integral attachment supports based on other aging mechanism considerations, as well as for the austenitic stainless steel RV cladding and nickel-based alloy CRDM nozzle and housing components that are exposed to borated water conditions. The applicant's identification of cracking as an applicable effect for these components is acceptable because it accounts for the potential for these components to crack either as a result of thermal fatigue or by stress corrosion cracking.

Reduction in fracture toughness is also of concern during the period of extended operation for some RV/CRDM components. The alloy steel weld and base metals in the RV beltline are subject to reduction in fracture toughness as a result of neutron embrittlement. Reduction in fracture toughness may also occur in certain types of CASS components as a result of prolonged exposure to service temperatures above 250°C (482°F) (i.e., as a result of thermal aging). The applicant has identified reduction in fracture toughness as an applicable effect for the RV beltline base metal and weld materials. The applicant addresses reduction of fracture toughness of the RV beltline materials in the TLAA for the RV materials, as given in Section 4.2 of the application. The staff' evaluation of the TLAA for the RV beltline materials is given in Section 4.2 of this SER.

The applicant also identified in Table 3.1-1 that the CRDM latch housing was fabricated from CASS; however, as stated in Section of 3.1.1 of the application, the applicant's CASS analysis did not identify that this component was susceptible to thermal aging because the component was centrifugally cast. The applicant therefore did not identify reduction in fracture toughness as an applicable effect for the CRDM latch housing. This is acceptable to the staff because it is in agreement with a staff position which states that reduction in fracture toughness is not an applicable effect for centrifugally cast CASS RCS components[3].

Inspection of bolted connections and components is part of the applicant's ISI program under ASME Section XI, Subsection IWB (Class 1) inspections. The ISI effort is based on the applicant's response to IE Bulletin 82-02, "Degradation of Threaded Fasteners in Reactor Coolant Pressure Boundary of PWR Plants," which addressed stress-corrosion cracking of SA 4140 low-alloy, high-strength steel bolting materials. Table 3.1-1 of NUREG-1800 identifies that high strength, low alloy steel bolted connections may be degraded by three potential aging effects: (1) stress corrosion cracking, (2) potential loss of material as a result of general or boric acid leakage corrosion, and (3) loss of preload as a result stress relaxation. The applicant has appropriately identified these effects for the RV bolts, studs, nuts and washers. This is acceptable to the staff because it is in agreement with the aging effects identified in Table 3.1-1 of NUREG-1800 for bolted connections of the RV and other RCS subsystems.

On the basis of the description of the internal and external environments, materials used, and the applicant's review of industry and plant-specific experience, the staff concludes that the applicant has identified all aging effects that are applicable for the RV and CRDM pressure boundary components.

3.1.3.2.2 Aging Management Programs

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2 Letter from C. I. Grimes (NRC) to D. J. Walters (NEI), *License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components,"* Project No. 690, dated May 2000.

In Table 3.1-1 of the LRA, the applicant lists the AMPs that will be used to manage the effects of aging in RV and CRDM pressure boundary components during the period of extended operation. They include:

- Chemistry Control program
- Fluid Leak Management program
- ISI Plan
- Alloy 600 Aging Management Review
- Reactor Vessel Integrity Program
- CRDM Nozzle and Other Vessel Closure Penetrations Inspection program
- RCS Operational Leakage Monitoring program
- Bottom-Mounted Instrumentation Thimble Tube Inspection program

In Table 3.1-1 of the LRA, the applicant lists all RV and CRDM pressure boundary components within the scope of the license renewal with their intended functions, material groups, and environment. Also, the table identifies the aging effects requiring management and the plant-specific AMPs required to manage these aging effects during the period of extended operation.

The Chemistry Control program (Section B.3.6 of Appendix B to the LRA) provides water quality that is compatible with the materials of construction used for the McGuire and Catawba RV and CRDM components in order to minimize loss of material and cracking. This program is developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience.

In Table 3.1-1 of the LRA, the applicant stated that cracking and loss of material associated with the thimble seal table would be managed solely by implementation of the chemistry control program. By letter dated January 28, 2002, the staff requested, in RAI 3.1-3, the applicant to clarify how implementation of the chemistry control program by itself would be sufficient to manage loss of material and cracking in the thimble seals. In its response dated April 15, 2002, the applicant stated that, in addition to the Chemistry Control program, the thimble seals are visually inspected during startup from each outage to ensure they are not leaking and that the seals are disconnected every outage so that the flux thimbles may be retracted during refueling. The applicant stated that, prior to restart, the flux thimbles are reinserted and the high pressure seal is reinstalled, and that these connections are visually inspected for leakage during startup of the units. The applicant stated that this inspection is part of the ISI plan, ASME Section XI, Table IWB-2500, Examination Category B-P. In its response to RAI 3.1.3-1, the applicant also provided a revised AMR for the thimble seal table that credited the ISI plan as an additional program for managing cracking and loss of material in the thimble seals. The staff finds this to be acceptable because the applicant has proposed to use both a preventative/mitigative program and an inspection-based program as a means of managing aging effects in the thimble seals.

The staff has evaluated the Chemistry Control program as a common AMP and found it to be acceptable for managing the aging effects identified for RV and CRDM pressure boundary components. The staff’s evaluation of this AMP is documented in Section 3.0 of this SER.

The Fluid Leak Management program (Section B.3.15 of Appendix B to the LRA) was developed by the applicant in response to NRC Generic Letter 88-05. Inspections are performed to provide reasonable assurance that borated water leakage from the reactor coolant pressure boundary does not lead to undetected loss of material on the external surface of RC piping and associated components, and specifically for those made out of carbon steel or low alloy steel. The staff's evaluation of this AMP is documented in Section 3.0 of this SER. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for RV and CRDM pressure boundary components.

For the RV and CRDM components, the ISI Plan (Section B.3.20 of Appendix B to the LRA) manages the aging effects of loss of material, cracking, and gross loss of preload. The scope of the ISI plan for Class 1 components complies with the requirements of ASME Section XI, Subsections IWB. Depending on the examination category, the methods of inspections may include visual, surface and/or volumetric examination of weld locations susceptible to aging degradation. The examination methods required by Subsection IWB for implementation either directly inspect for loss of material and cracking in the Class 1 components and are capable of detecting the aging effects, or inspect for indications of reactor coolant leakage which, in the case of bolted connections, would be indicative of a loss of preload in the bolt. Management of reduction in fracture toughness for the RV intermediate shell and lower shell materials is addressed in the applicant's TLAAs for the RVs, as provided in Section 4.2 of the application. The staff evaluates these TLAAs in Section 4.2 of this SER. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the reactor vessel and CRDM pressure boundary. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for RV and CRDM pressure boundary components. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

The Alloy 600 Aging Management Review is described in Section B.3.1 of the LRA. The applicant stated that it will implement this review to ensure that nickel-based alloy locations are adequately managed by the ISI Plan (Section B.3.20 of Appendix B to the LRA), or other pertinent aging management programs such as the CRDM Nozzle and Other Vessel Head Penetration program (Section B.3.9 of Appendix B to the LRA), the Reactor Vessel Internals Inspection program (Section B.3.27 of Appendix B to the LRA), or the Steam Generator Surveillance program (Section B.3.3.1 of Appendix B to the LRA). According to the LRA, this program is a review that utilizes industry and Duke operating experience to define the additional inspection work that needs to be carried out in support of these two AMPs. The inspection methods and frequency of inspection for the Alloy 600/690, 82/182, and 52/152 locations for the period of extended operation will be adjusted as needed, based on the review. The staff has evaluated this AMP and found it to be acceptable for managing the aging effects identified for RV and CRDM pressure boundary components. The staff's evaluation of this AMP is documented in Section 3.1.2.2.2 of this SER.

The applicant credited the CRDM Nozzle and Other Vessel Closure Penetration Inspection program for managing cracking (specifically primary water stress corrosion cracking) of nickel-based RV head penetrations exposed to borated water environments to ensure that the pressure boundary function is maintained during the period of extended operation. This AMP is used in conjunction with the Fluid Leak Management program and the RCS Operational Leakage Monitoring Program (Section B.3.25 of Appendix B to the LRA) to manage the effects of aging of RV head penetrations. The staff's review of this AMP is documented in the following pages of this SER section.

The applicant has credited the Reactor Vessel Integrity program (Section B.3.26 of Appendix B to the LRA) for managing reduction in fracture toughness of RV beltline materials to assure that the pressure boundary intended function of the RV beltline is maintained for the period of extended operation. The program includes an evaluation of radiation damage based on the pre-irradiation and post-irradiation testing of Charpy-V-notch and tensile specimens. The applicant concludes that this AMP is capable of ensuring that RV degradation is identified and corrective actions are taken before allowable limits are exceeded. Neutron fluences used for the pressurized thermal shock (PTS), upper shelf energy, and pressure-temperature limit TLAAs are based on the latest RV surveillance capsule reports for the McGuire and Catawba units submitted to the staff as part of AMP B.3.26. The staff's review of this AMP is documented in the following pages of this SER section.

The Bottom-Mounted Instrumentation (BMI) Thimble Tube Inspection program (Section B.3.5 of Appendix B to the LRA) is a condition monitoring program. In NRC Bulletin No. 88-09 and Information Notice No. 87-44, the staff identified flow-induced vibration as a cause for wear (i.e., thinning) of the thimble tubes, resulting in degradation of the RCS pressure boundary and potentially leading to non-insoluble leak of reactor coolant. The amount of vibration the thimble tubes experience is determined by plant-specific factors such as the gap distance from the lower core plate to the fuel assembly instrument tube, the amount of clearance between the thimble tube and the guide or instrument tube, the axial component of the local fluid velocity, the thickness of the thimble tube, and the moment of inertia of the thimble tube. The staff concluded in the bulletin that the only effective method for determining thimble tube integrity is through plant-specific inspections and periodic monitoring. The program is designed to identify loss of material due to wear in the bottom-mounted instrumentation thimble tubes prior to leakage. It uses eddy current techniques on all of the thimble tubes to estimate loss of material. The frequency of inspection is based on an analysis of data obtained using wear rate relationships developed in Westinghouse report WCAP-12866, "Bottom-Mounted Instrumentation Flux Thimble Wear," dated 1991. The staff's review of this AMP is documented in the following pages of this SER section.

The RCS Operational Leakage Monitoring program is designed to provide an additional line of defense against aging effects that any result in leakage due to cracking and loss of mechanical closure integrity. Both McGuire and Catawba have continual RCS leakage limits and system surveillance requirements as described in their TS. In the scope of this AMP, the applicant stated that it also manages, in part, aging effects for Inconel penetrations through the RV head. The staff's evaluation of the common AMP is documented in the following pages of this SER section.

<u>CRDM Nozzle and Other Closure Penetration Inspection Program (VHP Nozzle Program)</u>

The applicant provides a description of the VHP Nozzle Program in Section B.3.9 of Appendix B to the McGuire/Catawba LRA. The applicant states that the purpose of the VHP Nozzle Program is to manage cracking of nickel based alloy reactor vessel head penetration (VHP) nozzles that are exposed to the borated water environment to assure that the pressure boundary function is maintained during the period of extended operation. The applicant also states that the Fluid Leak Management Program, which performs walkdowns looking for evidence of leakage, and the RCS operational leakage monitoring program, which monitors system leakage are used in conjunction with the VHP Nozzle Program to manage aging of the reactor vessel head penetrations. This program is a condition monitoring program credited with managing PWSCC of high nickel alloy reactor vessel head penetrations and is a complimentary program to the ISI Plan.

The applicant credited the McGuire/Catawba VHP Nozzle Program for managing aging effects in the McGuire/Catawba Alloy 600 VHPs. The staff evaluated the VHP Nozzle Program on the following seven program attributes for the program:

1. Scope of Program
2. Preventative Actions
3. Parameters Monitored or Inspected
4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria
7. Operating Experience

The staff evaluates the other three program attributes for the VHP Nozzle Program (i.e., [Confirmatory Actions], [Corrective Actions] and [Administrative Controls]) as part of its review of the applicant's Quality Assurance Program. The staff evaluates the Quality Assurance Program in Section 3.0.4 of this SER.

In accordance with the issues raised in Generic Letter (GL) 97-01 and NRC Bulletins 2001-001, 2002-01, and 2002-02, the staff considers that aging management of PWSCC in the McGuire/Catawba VHP nozzles is an emerging issue that needs to be resolved in coordination with on-going industry efforts for the current license period. However, since the staff considers that the docketed information in the applicant's responses to RAI B.3.9-1 and to NRC Bulletins 2001-001 and 2002-01 provides the current updated CLB for the VHP Nozzle Program, the staff also evaluated the VHP Nozzle Program against this docketed information. The CLB for the applicant's VHP nozzles and the VHP Nozzle Program will be updated when the applicant submits its response to NRC Bulletin 2002-02 within 30 days of its issuance.

[Scope] The applicant stated that the scope of the VHP Nozzle Program includes the control rod drive mechanism nozzles and head vent penetrations of each reactor vessel. These penetrations include 78 Control Rod Drive Mechanism (CRDM) type penetrations, and one head vent penetration. The four auxiliary head adapter penetrations on each head are visually inspected as part of the VHP Nozzle Program and volumetrically examined by the ISI Plan. The applicant's scoping attribute for this program is acceptable to the staff because it accounts for inspections of all Alloy 600 penetration nozzles that are used in the McGuire and Catawba RV head designs.

[Preventive Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The applicant's [Preventive Actions] attribute for this program is acceptable to the staff because the program uses an inspection-based approach to monitor for aging in the VHP nozzles for the Catawba and McGuire units and does not rely on actions to prevent the initiation of aging effects or to mitigate the amount of aging that may occur.

[Parameters Monitored or Inspected] The applicant stated that the VHP Nozzle Program monitors cracking of nickel-based alloy nozzles with partial penetration welds in the reactor vessel closure head. The applicant's [Parameters Monitored or Inspected] attribute for this program is acceptable to the staff because industry experience indicates that PWSCC is an applicable aging effect in the Alloy 600 VHP nozzles of PWRs.

[Detection of Aging Effects]   The applicant states that, in accordance with information provided in the Monitoring and Trending program attribute below, the VHP Nozzle Program will detect cracking of nickel based alloy reactor vessel head penetrations prior to loss of component intended function. The staff's evaluation of the [Detection of Aging Effects] attribute is incorporated into the staff evaluation of the applicant's [Monitored or Trending] attribute that follows.

[Monitoring and Trending] The applicant stated that the VHP Nozzle Program will inspect the control rod drive mechanism type penetrations, the head vent penetration and the auxiliary head vent penetration. This program will consist of both visual and volumetric examinations. Visual inspections apply to all penetrations in the reactor vessel head. Visual inspections of all accessible CRDM type penetrations will be completed every refueling outage. During each 10- year ISI interval, insulation is removed and 100 percent visual inspection of the outside surface of the head will be performed. This inspection will include CRDM type penetrations, auxiliary head adapter penetrations and the head vent. Volumetric inspections within this program apply to the CRDM type penetrations and the head vent penetration. The auxiliary head adapter penetrations are inspected volumetrically by the ISI Plan.

Currently, eddy current inspection is used for detection of cracking. A combination of eddy current, ultrasonic, and liquid penetrant will be used for sizing indications. These methods may be updated based on industry experience. The number of penetrations inspected will be based on both Duke specific experience gained through inspections performed at Oconee and through industry experience on similar Westinghouse plants shared through the Westinghouse Owner's Group Program. For McGuire, this new inspection will be completed following issuance of renewed operating licenses for McGuire Nuclear Station and by June 12, 2021 (the end of the initial license of McGuire 1). For Catawba, this new inspection will be completed following issuance of renewed operating licenses for Catawba Nuclear Station and by December 6, 2024 (the end of the initial license of Catawba 1). Due to length of time in operation, it is expected that Unit 1 results will provide a leading indicator for Unit 2 results at each station. The results of these inspections will form the basis for timing of future inspections. The timing of these inspections may change based on either Duke specific or industry experience.

The current industry-wide program for monitoring cracking in Alloy 600 VHP nozzles is based on an integrated ranking and monitoring program for VHP nozzles developed by the industry in the late 1990s. This program is based on the industry's generic and plant-specific responses to GL 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," which ranked the susceptibility of Alloy 600 VHPs to PWSCC based on probabilistic cracking models. Based on a conservative assessment, the applicant indicated that the VHP Nozzle Program, in part, would call for eddy current examinations of McGuire 1 and Catawba 1 VHP nozzles prior to June 12, 2021, and December 6, 2024, respectively. The applicant also indicated that a combination of eddy current testing, ultrasonic testing, and dye-penetrant testing would be used to size any recordable indications that result from the eddy current examinations used for detection purposes. The applicant has indicated that, due to length of time in operation, it is expected that Unit 1 results will provide a leading indicator for Unit 2 results at each station. The results of these inspections will form the basis for timing of future inspections. The timing of these inspections may change based on either Duke specific or industry experience.

Between November 2000 and April 2001, reactor coolant pressure boundary (RCPB) leakage was identified from the VHP nozzles of four U.S. PWR-design light water reactor facilities. Supplemental examinations of the degraded nozzles indicated the presence of circumferential cracks in four of the CRDM nozzles. These findings are significant in that the cracking was reported to initiate from the OD side of the nozzle, either in the associated J-groove welds or heat-affect-zones, and not from the inside surface of the nozzles as was assumed in the industry responses to GL 97-01. In regard to this experience, the degradation was severe enough to penetrate through the RCPB for the nozzles and represented the first report of circumferential cracking in U.S. VHP nozzles.

In response to the identified cracking, the NEI and the Materials Reliability Program (MRP) submitted Topical Report TP-1001491, Part 2, "PWR Materials Reliability Program Interim Alloy 600 Safety Assessments for US PWR Plant (MRP-44)." This report included a revised susceptibility ranking model for PWR plants. This revised model placed the VHP nozzles for the McGuire and Catawba units within 120-145 EFPY of the time the same conditions were evident at the plant which identified the circumferential cracking in its CRDM nozzles. On August 3, 2001, the NRC issued NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Coolant Pressure Vessel Head Penetration Nozzles," to address the potential safety implication of these findings. The bulletin (ADAMS Accession No. ML012080284) emphasized the need to use effective examination techniques capable of detecting flaws in these nozzles, using an approach that was consistent with the relative susceptibility of the VHP nozzles, and recommended an inspection-based program for the U.S. PWR industry that was based on the revised susceptibility rankings provided in the MRP-44 report.

In RAI B.3.9-1 the staff informed the applicant that the program description for the VHP Nozzle Program, as described in Section B.3.9 of Appendix B the LRA, did not specify whether the applicant would continue to be a participant in the NEI program for managing PWSCC type aging in Alloy 600 VHP nozzles of U.S. PWR designed facilities, and whether the applicant would continue to use the program as a basis for evaluating the Alloy 600 VHPs in the McGuire and Catawba nuclear units during the proposed extended operating terms for the units. With respect to this program the staff asked the applicant to: (1) discuss how the recent circumferential cracking discussed in NRC Bulletin 2001-01 would impact the aging management program for the McGuire and Catawba CRDM penetration nozzles and other vessel head penetration nozzles; and (2) discuss what additional activities the applicant would be participating in, if any, that will be implemented as part of this program.

In its response to RAI B.3.9.1, dated April 15, 2002, the applicant stated the following:

> ...the recent circumferential cracking issue discussed in Bulletin 2001-001 will not affect the . . [VHP Nozzle Program] . . as proposed in the application. Since circumferential cracking was identified at Oconee Nuclear Station in November 2000, Duke has been aware of the concern prior to NRC issuance of Bulletin 2001-001. The Oconee experience was taken into account during development of the program described in Section B.3.9 of the application. As discussed under Monitoring and Trending in the program description, Duke has committed to base the number of penetrations inspected on Duke specific experience gained through inspections performed at Oconee and through industry experience on similar Westinghouse plants shared through the Westinghouse Owners Group.

In March 2002, and since the issuance of RAI B.3.9-1, a bare surface examination of the Davis Besse reactor vessel head has been completed. The licensee determined that a number of CRDM nozzles for the unit had severely degraded and leaked as a result of PWSCC. In two of these leaking nozzles, boric acid residue buildup had been severe enough to induce wastage of the ferritic steel in the reactor vessel head adjacent to the penetration nozzles. The severity of the wastage in one of the nozzles was critical because the wastage had corroded away the adjacent ferritic material in the upper RV head completely down to the head's stainless steel cladding. To address the potential safety implication of these findings to the industry as a whole, the NRC issued NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," dated March 18, 2002, and NRC Bulletin 2002-02, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," dated August 9, 2002.[4]

Duke provided its response to Bulletin 2002-01 for the McGuire and Catawba units by letter dated April 1, 2002 (ADAMS Accession No. ML0210502920). In its responses to both Bulletins (2001-01 and 2002-01), the applicant indicated that the current program includes the following provisions: (1) inspection of the vessel head, including one-time visual examinations of the bare surfaces of the McGuire and Catawba upper vessel heads as recommended in Bulletin 2002-01; (2) enhancement or augmentation of inspections if leakage is detected in any of the McGuire or Catawba VHP nozzles; (3) repairs of leaking VHP nozzles either in compliance with the repair requirements of Section XI of the ASME Code or in acceptable alternatives approved by the NRC; and (4) cleaning or removal of boric acid residues if they are detected on the RV heads of the McGuire and Catawba reactor units.[4]

The information in the applicant's responses to RAI B.3.9-1, GL 97-01, and NRC Bulletins 2001-01 and 2002-01 indicates that the applicant is an active participant in the NEI program for monitoring and controlling PWSCC in VHP nozzles. The current program, as described and updated in the applicant's responses to Bulletins 2001-01 and 2002-01, indicates that the applicant has responded to the issues and action requests raised in the Bulletins.[4] The staff and nuclear power industry are pursuing resolution of this issue, and the staff is evaluating potential changes to the requirements governing inspections of Alloy 600 VHP nozzles and PWR upper RV heads (specifically with respect to non-destructive examinations and the ability to detect cracking in the VHP nozzles prior to loss of material in the upper RV heads). This is an emerging issue that has not yet been resolved. It raises questions about the capability of the VHP nozzles to perform their intended function during the current license term. The Commission recognized that aging issues could arise during the license renewal review that raise questions about the capability of structures or components to perform their intended function during the current term of operation, and provided for such issues in 10 CFR 54.30, which requires that such issues be addressed under the current license, rather than as part of the license renewal review. Therefore, this issue is beyond the scope of this license renewal review, pursuant to 10 CFR 54.30(b).

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4 The applicant will comply with the reporting requirements of the bulletin and submit its responses to NRC Bulletin 2002-02 within 30 days of the bulletin's date of issuance (August 9 2002). When submitted, the applicant's responses to NRC Bulletin 2002-02 will update the CLB for the McGuire and Catawba VHP nozzles and the applicant's VHP Nozzle Program.

However, since this issue might not be resolved prior to issuance of the renewed operating licenses for the McGuire and Catawba units, the staff requests the applicant to commit to implementing any actions, as part of the VHP Nozzle Program, that are agreed upon between the NRC, NEI, MRP, and the nuclear power industry to monitor for, detect, evaluate, and correct cracking the VHP nozzles of U.S. PWRs, specifically as the actions relate to ensuring the integrity of VHP nozzles in the McGuire and Catawba upper RV heads during the extended period of operation. This commitment will ensure that the applicant's VHP Nozzle Program (as described in the McGuire and Catawba UFSARs) will be capable of monitoring for, detecting, evaluating (see the discussion of evaluation criteria guidelines in the staff's evaluation of acceptance criteria below), and correcting cracking in the McGuire and Catawba VHP nozzles and associated upper RV heads before unacceptable degradation of the VHP nozzles or associated upper RV heads occurs. This issue is characterized as open item 3.1.3.2.2-2. Any updates to the VHP Nozzle Program that result from resolution of this issue should be reflected in the UFSARs for the McGuire and Catawba units.

[Acceptance Criteria] The applicant stated, for the visual inspection, any boron detected on the outer surface of the vessel head due to penetration leakage is unacceptable. The applicant stated, for the volumetric examination, axial flaws detected during volumetric inspection will be analyzed and accepted via the NUMARC acceptance criteria which was approved by the NRC in their SER dated November 19, 1993. Circumferential flaws will be analyzed and addressed on a case-by-case basis by the NRC. The applicant's responses to NRC Bulletins 2001-01 and 2002-01 update this to provide acceptance criteria for visual examinations performed on bare surfaces of the McGuire and Catawba RV heads. The applicant's responses to NRC Bulletins 2001-01 and 2002-01 state that the applicant considers any signs of boric acid residues on the surfaces of the reactor vessel heads to be indications of reactor coolant (borated water) leakage and that indications of this nature will need additional evaluation and corrective action. However, the staff is currently resolving with the industry exactly what the requirements should be for inspections of VHP nozzles in U.S. PWRs, and the scope of any actions and/or activities agreed upon between the NRC and the industry for resolution of this issue will need to include exactly what the acceptance criteria will be for the VHP nozzle inspection techniques that are agreed on between the staff and the industry and what the corrective actions should be if cracking is detected. In the interim, the staff has issued revised flaw evaluation criteria guidelines that may be used as the latest flaw acceptance criteria for VHP nozzles.[5] This matter is addressed as part of the commitment discussed in open item 3.1.3.2.2-2.

[Operating Experience] The applicant stated that, on April 1, 1997, the NRC issued GL 97-01, "Degradation of CRDM/CEDM Nozzle and Other Vessel Closure Head Penetrations." GL 97-01 indicated that the NRC did not object to individual licensees basing their inspection plans for vessel closure head penetrations on an integrated industry program. The applicant stated that McGuire and Catawba Nuclear Stations are participants in the WOG generic program to address GL 97-01 and that the industry's generic responses to GL 97-01 placed the VHP nozzles for domestic PWRs into three susceptibility groups based on the probability of having a 75 percent through wall crack. The applicant stated that the VHP nozzles for the McGuire and Catawba RV heads are in the greater than 15 EFPY grouping (would not expect a 75 percent through wall crack for more than 15 EFPY from January 1, 1997), which reflects the lowest

5 Letter from Jack R. Strosnider (NRC) to Alex Marion (NEI), "Flaw Evaluation Criteria," September 24, 2001.

susceptibility to cracking of the CRDM penetrations. The staff notes that this is based on the industry's GL 97-01 susceptibility rankings.

The applicant stated that, on April 30, 2001, the Nuclear Regulatory Commission issued Information Notice 2001-05, Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3. This Information Notice gives details of inspections performed on the reactor vessel head where significant circumferential indications were found. The applicant's responses to Bulletins 2001-001 and 2002-01 provide the applicant's updated susceptibility rankings for the McGuire and Catawba VHP nozzles and updated evaluations of how the VHP nozzle circumferential cracking event at the Oconee nuclear station and boric acid wastage event of the Davis Besse RV head impact the applicant's proposed schedules and methods for monitoring PWSCC in the McGuire and Catawba VHP nozzles. The applicant's [Operating Experience] program attribute, as updated by the applicant's responses to NRC Bulletins 2001-01 and 2002-01, provides the applicant's review of pertinent VHP nozzle degradation events and reflects the applicant's most current CLB for resolving the issue of monitoring for PWSCC in the VHP nozzles of the McGuire and Catawba units. The staff anticipates that this will be updated to reflect the applicant's response to Bulletin 2002-02. This is acceptable since it meets the requirements of 10 CFR Part 54.

FSAR Supplement: The applicant's FSAR Supplement for the VHP Nozzle Program is documented in Section 18.2.6 of Appendix A to the LRA and provides an overview of the program as described in Section B.3.9 of Appendix B to the LRA. The applicant should modify the FSAR supplement descriptions of the VHP Nozzle Program to reflect the docketed information in the applicant's responses to RAI B.3.9-1 and to NRC Bulletins 2001-01 and 2002-01, as well as the information that will be provided in the applicant's response to NRC Bulletin 2002-02. Additionally, the applicant should modify its UFSARs for both McGuire and Catawba to reflect the resolution of the VHP nozzle integrity issue associated with open item 3.1.3.2.2-2 to the extent that such resolution impacts the AMP for license renewal.

In conclusion, the staff reviewed the information in Section B.3.9 of the LRA, the applicant's response to RAI B.3.9-1, and the information provided in the applicant's responses to NRC Bulletins 2001-01 and 2002-01. With the exception of open item 3.1.3.2.2-2, the staff finds that the program will be an acceptable means of monitoring and controlling age-related degradation in McGuire and Catawba VHP nozzles during the extended period of operation for each unit.

<u>Reactor Vessel Integrity Program</u>

The applicant describes its reactor vessel integrity program in Section B.3.26 of the LRA. This AMP is applicable to both McGuire and Catawba RVs. The applicant credits this program for managing the reduction in fracture toughness of RV beltline materials to assure that the pressure boundary of the beltline materials is maintained during the period of extended operation. In the program, the effects of irradiation will be determined by pre-irradiation and post-irradiation testing of Charpy V-notch and tensile samples.

The staff reviewed the applicant's description of the program and the program's attributes to determine whether the applicant had demonstrated that it will adequately manage the applicable effects of aging in RV beltline region materials during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The scope of this AMP is stated by the applicant to include all of the RV beltline materials, as defined in 10 CFR 50.61(a)(3). This program includes an evaluation of radiation damage based on pre-irradiation and post-irradiation samples periodically withdrawn from the RVs. The monitoring and trending within this AMP include fluence received by the specimens, effective full power years, cavity dosimetry, and monitoring of plant changes. Tables are included in the LRA to specify the RV irradiation capsule withdrawal schedules for McGuire and Catawba units.

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in Section B.3.26 of the LRA to determine if the reactor vessel integrity program will adequately manage the reduction in fracture toughness of the RV beltline material base metal and weld materials so that the RV intended functions will be maintained consistent with the CLB throughout the period of extended operation for all four reactor vessels.

The staff evaluated the Reactor Vessel Integrity Program on the following seven program attributes for the program:

1. Scope of Program
2. Preventative Actions
3. Parameters Monitored or Inspected
4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria
7. Operating Experience

The staff's evaluations of these program attributes are given in the paragraphs that follow. The staff's evaluation of the other three program attributes (confirmatory actions, corrective actions, and administrative controls) for the Reactor Vessel Integrity program is documented in Section 3.0.4 of this SER.

[Program Scope] The scope of the reactor vessel integrity program includes all beltline materials as defined in 10 CFR 50.61(a)(3). The scope of the test program for these materials involves the measurement of irradiation effects by pre-irradiation and post-irradiation testing of Charpy V-notch and tensile samples. This is consistent with the scope of RV material surveillance programs required to be implemented in accordance with the requirements of 10 CFR Part 50, Appendix H, and is therefore acceptable to the staff.

[Preventive Actions] In accordance with the applicant, no actions are taken as part of this program to prevent aging effects or mitigate aging degradation of the RV. The reactor vessel integrity program is a surveillance monitoring program designed to monitor for materials property changes, and specifically for loss of fracture toughness, in the materials used to fabricate the RVs for the McGuire and Catawba reactor units and to comply with the reactor vessel material surveillance program capsule withdrawal and testing requirements of 10 CFR Part 50, Appendix H. The program uses Charpy-V impact testing of the surveillance capsule specimens as its method for monitoring changes (losses) in fracture toughness in the RV beltline materials. Surveillance programs implemented in accordance with the requirements of 10 CFR Part 50, Appendix H, are not designed to prevent or mitigate aging effects before their occurrence. The staff therefore concludes the applicant's [preventative actions] is acceptable because the program is not designed to be a preventative or mitigative type program for precluding aging effects prior to their occurrence.

[Parameters Monitored or Inspected] The applicant stated that this AMP monitors reduction of fracture toughness of beltline materials due to irradiation embrittlement. This is consistent with the scope of RV material surveillance program required to be implemented in accordance with the requirements of 10 CFR Part 50, Appendix H, and is therefore acceptable to the staff.

[Detection of Aging Effects] The applicant stated that the effects of aging will be detected based on the data obtained in the monitoring and trending effort from the RV material surveillance program. This is consistent with the scope of RV material surveillance programs required to be implemented in accordance with the requirements of 10 CFR Part 50, Appendix H and is therefore acceptable to the staff.

[Monitoring and Trending] Each of the Duke RVs has six specimen capsules located in guide baskets welded to the outside of the neutron shield pads directly opposite the center portion of the core. McGuire 1 and Catawba 2 capsules contain specimens that are oriented parallel and perpendicular to the principal rolling direction of the limiting shell plate in the core region. McGuire 2 and Catawba 1 specimens are oriented parallel and perpendicular to the principal forging direction of the limiting core region shell forging. Associated weld and heat-affected-zone specimens are also included in the capsules. From tests carried out according to industry approved industry standards, the effects of irradiation and the neutron fluence values for the RV beltline materials are estimated. The applicant stated that these data are used to analyze the upper shelf energy values and RT_{PTS} values used for the upper shelf energy and PTS structural integrity assessments for the reactor vessel beltline materials, and to generate pressure-temperature curves for the future operation of each RV (Refer to TLAA Sections 4.2.1, 4.2.2 and 4.2.3 of the application).

The staff reviewed the surveillance capsule schedules in Tables B.3.26-1 and B.3.26-2 of the LRA. For McGuire 1, capsule “W” is a stand-by capsule and would be withdrawn at a fluence that is significantly above the equivalent of 60 years. The applicant needs to remove this capsule and place it in storage to prevent further exposure and preserve its ability to provide meaningful metallurgical data. For Catawba 2, capsule “U” is a stand-by capsule. It appears to the staff that this capsule should be inserted in the reactor vessel and begin to accumulate fluences in an operating environment for data collection purposes. The staff believes that the applicant should place all pulled capsules in storage so that they may be saved for future use. In addition, after the applicant has pulled all the capsules, it should use alternative dosimetry to monitor neutron fluence during the period of extended operation. The applicant needs to discuss its plans for this capsule with the staff. This issue is characterized as open item 3.1.3.2.2-1. The staff’s evaluation of the TLAAs for upper shelf energy, pressurized thermal shock, and the generation of pressure-temperature (P-T) limit curves are described in Sections 4.2.1, 4.2.2, and 4.2.3 of this SER, respectively.

[Acceptance Criteria] The applicant listed the acceptance criteria as follows:

- Charpy specimens removed from the surveillance capsules and tested to ensure that the upper shelf energy is greater than 50 ft-lb.
- Calculations of the reference temperature for pressurized thermal shock, $_{RT\ PTS}$, must be below the screening criteria of 270°F for plates, forgings, and longitudinal welds, and below 300°F for circumferential welds.
- Acceptable pressure-temperature curves must be maintained approved and current in the plant TS.

• Capsules included in the reactor vessel integrity program must be withdrawn on a schedule.

These acceptance criteria are consistent with the requirements for protection of the reactor vessels against pressurized thermal shock (PTS) events, as specified in 10 CFR 50.61, the requirements for upper shelf energy and P-T limits, as specified in 10 CFR Part 50, Appendix G, the requirements of 10 CFR 50.36 for incorporating the P-T limits for the reactor vessels and RCS into the plant TS, and the requirements for implementation of reactor vessel materials surveillance programs, as specified in 10 CFR Part 50, Appendix H. The staff therefore concludes that the acceptance criteria program attribute for reactor vessel integrity program is acceptable.

[Operating Experience] By letter dated January 28, 2002, the staff issued four RAIs (B.3.26-1, B.3.26-2, B.3.26-3, and B.3.26-4) relative to the fast neutron exposure of the McGuire and Catawba reactor pressure vessel beltline materials. Each RAI requested the following:

1. Why does the magnitude of the end-of-license fast neutron fluence projection at the pressure vessel inner diameter change as each surveillance capsule is withdrawn and analyzed?

2. Why does the location of the projected maximum exposure of the pressure vessel change as each surveillance capsule is withdrawn and analyzed?

The staff reviewed the LRA submittal and the applicant's responses to B.3.26-1, B.3.26-2, B.3.26-3, and B.3.26-4, dated April 15, 2002, in order to evaluate the acceptability of the fluence methodology and fluence values to be used for application to the Pressure Temperature curves and the calculation of the $_{RT\ PTS}$ for all four units. The applicant submitted four surveillance capsule reports to address the staff's RAIs on neutron fluence:

1. WCAP-15117, "Analysis of Capsule V and the Dosimeters from Capsules U and X from the Duke Power Company Catawba 1 Reactor Vessel Surveillance Program" by E. Terek et. al., Westinghouse Energy Systems, October 1998.

2. WCAP-15243, "Analysis of Capsule V and the Capsule Y Dosimeters from the Duke Energy Catawba 2 Reactor Vessel Radiation Surveillance Program" by T. Laubham, et. al., Westinghouse Electric Company, LLC, September 1999.

3. WCAP-15253, "Duke Power Company Reactor Cavity Neutron Measurement Program for William B. McGuire 1 Cycle 12" by J. Perock et. al., Westinghouse Electric Company, LLC, July 1999.

4. WCAP-15334, "Duke Power Company Reactor Cavity Neutron Measurement Program for William B. McGuire 2 Cycle 12" by A. Fero, Westinghouse Electric Company, LLC, November 1999.

The staff determined that the four surveillance capsule reports (Refs 1-4, one for each unit) use a fluence computational methodology which adheres to the guidance of RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," U.S. Nuclear Regulatory Commission, March 2001, which provides the staff's bases for evaluating methodologies for neutron fluence dosimetry measurements and for calculating neutron fluence values used in reactor vessel structural integrity determinations. Since the applicant is using a computational neutron fluence methodology that meets the staff's recommended methods in RG 1.190, the staff finds that the applicant's methodology for calculating the neutron fluence values for the reactor vessel structural integrity TLAAs (specifically TLAAs 4.2.1, 4.2.2, and 4.2.3) and the resulting calculated neutron fluences values for the TLAAs are acceptable. The staff's evaluation of the TLAAs for upper shelf energy, pressurized thermal shock, and the generation of pressure-temperature (P-T) limit curves are described in Sections 4.2.1, 4.2.2, and 4.2.3 of this SER, respectively.

The staff notes that the assumed effective full power years (EFPYs) of operation to the end of the extended license is 54 EFPYs for the Catawba Units and 51 EFPYs for the McGuire Units. However, the historical load factors for McGuire 1 and 2 are 56.5 percent and 74 percent, respectively. For Catawba 1 and 2, the corresponding values are 77 percent and 75 percent. Achieving 54 and 51 EFPYs for the Catawba and McGuire Units respectively will require load factors considerably greater than 90 percent and 85 percent for Catawba and McGuire. This may be optimistic. If such load factors are not achieved, the result will be conservative for vessel fluence. To conform to the guidance of RG 1.190, the applicant will need to continue to maintain an uncertainty of less than 20 percent (1σ) in fluence estimates throughout the extended lives of the reactors.

FSAR Supplement: The staff reviewed Appendix A - FSAR Supplement (McGuire Section 18.2.21 and Catawba Section 18.2.20) of the LRA and found that the description of the reactor vessel integrity program is consistent with Section B.3.26 of the LRA.

In conclusion, on the basis of its review of the Reactor Vessel Integrity program, with the exception of open item 3.1.3.2.2-1 pertaining to the applicant's use of reactor vessel capsules, the staff finds that the continued implementation of this AMP provides reasonable assurance that the reduction in fracture toughness of RV beltline region materials will be adequately managed such that the intended function(s) of the RV will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Bottom-Mounted Instrumentation (BMI) Thimble Tube Inspection Program</u>

The applicant described its thimble tube inspection program in Section B.3.5 of Appendix B of the LRA. The applicant credits the BMI thimble tube inspection program for managing aging effects in the thimble tubes of the McGuire and Catawba reactor units, and specifically to manage loss of material due to wear in the BMI thimble tubes prior to leakage.

The staff reviewed this section of the application to determine whether the applicant has demonstrated that the aging effects of the bottom-mounted instrumentation (BMI) thimble tubes will be adequately managed by this program during the period of extended operation as required by 10 CFR 54.21(a)(3).

The applicant indicated that the thimble tubes are part of the reactor coolant pressure boundary and that the bottom-mounted instrumentation thimble tube inspection program is a condition monitoring program. The program utilizes eddy current test (ECT) to determine thimble tube wall thickness and predict wear rates for early identification of the need for corrective action before the potential thimble tube failure. The applicant also indicated that the bottom-mounted thimble tube inspection program was created and implemented in both plants in response to NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors." To date the applicant has performed six inspections at Catawba (three inspections per Unit) and four inspections at McGuire (two inspections per unit).

In accordance with 10 CFR 54.21 (a)(3), the staff reviewed the information in the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that intended function will be maintained consistent with the CLB throughout the period of extended operation for the bottom-mounted instrumentation thimble tubes.

The staff's evaluated of the Bottom-Mounted Thimble Tube Inspection Program on the following seven attributes for the program:

1. Program Scope
2. Preventive Actions
3. Parameters Monitored or Inspected
4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria
7. Operating Experience

The staff's evaluations of these program attributes are given in the paragraphs that follow. The staff's evaluation of the other three program attributes (confirmatory actions, corrective actions, and administrative controls) for the Bottom-Mounted Thimble Tube Inspection program is documented in Section 3.0.4 of this SER.

[Program Scope] The applicant indicated that the scope of the bottom-mounted instrumentation thimble tube inspection program includes all thimble tubes installed in each reactor vessel. This is acceptable to the staff because the program includes all thimble tubes within its scope for each reactor vessel.

[Preventive Actions] No actions are taken as part of this program to prevent aging effects or mitigate aging degradation. The staff agrees with this assessment because this program is a inspection-based detection program and does not include preventive actions.

[Parameters Monitored or Inspected] The applicant stated that the bottom-mounted instrumentation thimble tube inspection program monitors tube wall degradation of the BMI thimble tubes. The staff agrees with the applicant because failure of the thimble tubes would result in a breach of the reactor coolant pressure boundary. The staff also agrees with the applicant in that monitoring of the tube wall degradation of the BMI thimble tubes will ensure the tube structural integrity.

[Detection of Aging Effects] The applicant stated that, as stated below in the information provided in the Monitoring & Trending section, the bottom-mounted instrumentation thimble tube inspection program will detect loss of material due to wear prior to component loss of intended function. The staff agrees with this assessment because the BMI thimble tube inspection program includes the use of eddy current testing and ensures that all of the thimble tubes are inspected. The use of eddy current will detect tube wear or tube degradation and thus prevent tube failure which will result in a breach of reactor coolant pressure boundary. Therefore, the staff finds this approach acceptable.

[Monitoring & Trending] The applicant stated that inspection of the BMI thimble tubes is performed using eddy current testing (ECT). All of the thimble tubes are inspected. The frequency of examination is based on an analysis of the data obtained using wear rate relationships that are predicted based on Westinghouse research that is presented in WCAP-12866, “Bottom-Mounted Instrumentation Flux Thimble Wear.” These wear rates, as well as the results of the eddy current examinations are documented in site specific calculations. The ECT results are trended and inspections are planned prior to the refueling outage in which thimble tube wear is predicted to exceed the Acceptance Criteria specified below. The staff finds the monitoring and trending aspects of the BMI thimble tube inspection program acceptable because the tube inspections are planned based on site specific calculations. This will ensure that the thimble tubes continue to perform their intended function.

[Acceptance Criteria] The applicant indicated that the acceptance criteria for the BMI thimble tubes is 80 percent through wall (thimble tube wall thickness is not less than 20 percent of initial wall thickness). This acceptance criteria was developed by Westinghouse in WCAP 12866, "Bottom-Mounted Instrumentation Flux Thimble Wear," and reported to the NRC by Duke. The NRC staff finds the 80 percent through wall acceptance criteria to be acceptable because the remaining 20 percent will provide adequate structural integrity until the tube is capped or replaced. Also, the maximum number of thimble tubes that can be capped on a unit is 14 and a minimum of 75 percent or 44 of 58 total tubes are required to be in service in order to perform core power distribution surveillance.

[Operating Experience] On July 26,1988, the NRC issued IE Bulletin 88-09, “Thimble Tube Thinning in Westinghouse Reactors.” The NRC requested that inspection programs be implemented that included the following:

- The establishment, with technical justification, of an appropriate thimble tube wear acceptance criterion (for example, percent through wall loss). This acceptance criterion should include allowances for such items as inspection methodology and wear scar geometry uncertainties.
- The establishment, with technical justification, of an appropriate inspection frequency (for example, every refueling outage).
- The establishment of an inspection methodology that is capable of adequately detecting wear of the thimble tubes (such as eddy current testing).

The applicant has implemented a program at McGuire and Catawba that meets these criteria based on a proprietary study performed for the Westinghouse Owner’s Group.

Duke indicated that, since IE Bulletin 88-09 was issued, three inspections have been performed on Catawba 1 and three on Catawba 2 thimble tubes. The inspections on Unit 1 were performed during End Of Cycle (EOC) 1EOC-3 (1988), 1EOC-7 (1993) and 1EOC- 11 (1999). The Inspections on Unit 2 were performed during 2EOC-2 (1989), 2EOC-3 (1990), and 2EOC-5 (1993). The inspections did not detect significant changes in wear rates for either unit. Currently, no tubes are capped on Unit 1 and two tubes are capped on Unit 2 due to wear. Wear projections performed in the referenced calculations have determined that further eddy current testing will not be required until 1EOC-7 (2008) and 2EOC-15 (2007), respectively for Units 1 and 2, barring significant changes in cycle length or reactor geometry.

Similar inspections have been performed on McGuire 1 and 2. Unit 1 has been inspected twice, during 1EOC-5 (1988) and 1EOC- 14 (2001) with 10 tubes showing detectable wall loss. Two additional tubes were capped due to other types of damage. Unit 2 was inspected during 2EOC-5 (1989) and 2EOC-8 (1993), with eight tubes showing wear. The future inspections are currently planned to occur at 1EOC-19 (2008) for Unit 1 and 2EOC- 16 (2005) for Unit 2. The staff finds that the McGuire and Catawba operating experience confirms that the BMI thimble tube inspection program is effective to detect tube wear and tube degradation.

FSAR Supplement: The applicant provided in Appendix A-1 (McGuire) and A-2 (Catawba) new FSAR sections describing the bottom-mounted instrumentation thimble tube inspection program. The information provided for the FSAR is consistent with the program described in Appendix B and no changes are required.

In conclusion, the staff has reviewed the Bottom-Mounted Instrumentation Thimble Tube inspection, as described in Section 3.3.5 of Appendix B of the LRA. On the basis of its review, the staff finds that the applicant has demonstrated that this AMP will adequately managed aging effects identified for the reactor vessel thimble tubes so that there is reasonable assurance that their intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Reactor Coolant System Operational Leakage Monitoring Program

In Section B.3.25 of Appendix B of the LRA, the applicant described the Reactor Coolant System Operational Leakage Monitoring Program. The purpose of the Reactor Coolant System Operational Leakage Monitoring Program is to provide an additional line of defense against aging effects that may result in leakage due to cracking and loss of mechanical closure integrity. McGuire and Catawba have a continual reactor coolant system technical specification leakage limit and system surveillance requirement as defined in their technical specifications. The Reactor Coolant Operational Leakage Monitoring Program Is a condition monitoring program that provides reasonable assurance that leakage will be detected prior to loss of reactor coolant system function.

The staff reviewed the LRA to determine whether the applicant has demonstrated that this program will adequately manage the applicable effects of aging during the period of extended operation. It was noted that this program is not a new aging management program, but is an ongoing requirement of the technical specifications for the McGuire and Catawba units, as required by 10 CFR 54.21(a)(3).

The staff's evaluated of the Reactor Coolant System Operational Leakage Monitoring Program on the following seven attributes for the program:

1. Program Scope
2. Preventive Actions
3. Parameters Monitored or Inspected
4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria
7. Operating Experience

The staff's evaluations of these program attributes are given in the paragraphs that follow. The staff's evaluation of the other three program attributes (confirmatory actions, corrective actions, and administrative controls) for the Reactor Coolant System Operational Leakage Monitoring Program is documented in Section 3.0.4 of this SER.

[Scope] The applicant described the scope of the reactor coolant operational leakage monitoring program as all reactor coolant components that contain coolant; however it is specifically credited with managing aging of bolted closures on the steam generators, pressurizer, and reactor coolant pumps as well as the Inconel penetrations on the reactor vessel head and steam generator tubes. The staff noted that the applicant relies on a combination of the following programs: reactor coolant system operational leakage monitoring program, chemistry control program, and the ISI program to manage cracking and loss of mechanical integrity of the subject components. The staff reviewed the scope of the program and concluded that because it is comprehensive in that it includes those components that may affect the integrity of reactor coolant system, the scope is appropriate to determine the effects of aging, in part, on those items within the program scope.

[Preventive or Mitigative Actions] The applicant indicated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff considers the monitoring program to be designed to identify leakage and allow corrective action to be taken prior to loss of component function. Therefore the staff agrees that there is not a need for preventive actions.

[Parameters Monitored or Inspected] The applicant stated that the reactor coolant system operational leakage monitoring program monitors reactor coolant system operational leakage and steam generator primary to secondary leakage. Because the program is required by plant technical specifications and is capable of identifying leakage at low levels, the staff finds the monitoring to be appropriate for the stated purpose of the program.

[Detection of Aging Effects] The applicant stated that the reactor coolant system operational leakage monitoring program is capable of detecting cracking of the reactor coolant system pressure boundary and loss of mechanical closure integrity of bolted closures in cases where leakage is occurring. Because the monitoring system is required by the plant Technical Specifications and the system is continuously monitored, the staff concludes that it is capable of detecting aging effects.

[Monitoring and Trending] The applicant stated in the LRA that the method for monitoring reactor coolant system operational leakage is specified in McGuire and Catawba Technical

Specifications 3.4.13, RCS Operational Leakage, and 3.4.15, RCS Leakage Detection Instrumentation.

The NRC's regulations, in General Design Criterion (GDC) 30 of Appendix A to 10CFR50, require a means to detect and, to the extent practical, to identify the location of the source of reactor coolant system leakage. Regulatory Guide 1.45 describes methods acceptable to the NRC staff for selecting leakage detection systems. The primary method used by the applicant to detect leakage into the containment is measurement of the containment floor and equipment drain sump level. The sump level rate of change is calculated by the plant computer and can detect a one gpm leak within an hour. Leakage from the reactor coolant, main steam and feedwater systems can be detected in this way. The containment ventilation unit condensate drain tank level change is another method used by the applicant to detect leakage. This system is also capable of detecting a 1 gpm leak. Radioactivity monitoring of particulate and gaseous radiation levels is also indicative of reactor coolant system leakage because of the activity levels contained within the reactor coolant system during operation of the plant. Primary to secondary leakage from steam generator tubes is detected by effluent monitoring (for activity) within the secondary steam and feedwater systems.

The applicant performs a reactor coolant water inventory balance every 72 hours at steady state operation as specified in plant technical specifications to verify that leakage is within allowable limits. Steam Generator primary to secondary leakage is monitored continuously using an operator aid computer point, radiation monitors, condensate steam air ejector off gas or secondary tritium samples depending on monitoring equipment availability and operating mode.

Because the monitoring program meets NRC requirements as noted above, and is capable of identifying leaks as small as one gpm, the staff finds that the monitoring activity is acceptable for this program.

[Acceptance Criteria] The acceptance criteria for the reactor coolant operational leakage monitoring program are found in the plant technical specifications (LCO3.4.13, RCS Operational Leakage). Because the technical specifications have been reviewed and approved by the staff; the staff finds this to be acceptable.

[Operating Experience] The applicant performed a search of licensee event reports (LERs) to demonstrate the effectiveness of the reactor coolant system operational leakage monitoring program for McGuire and Catawba. Many of the LERs were maintenance issues; however, several identified what the applicant considered to be age-related events. Some of these events included: leakage due to loose valve bonnet bolts, leakage from an incore thermocouple fitting, a leaking compression fitting and a weld failure due to fatigue resulting from cavitation. In all of the above cases, a determination was made that the events had no significance regarding the health and safety of the public.

The applicant noted that another use of this program, especially prior to steam generator replacement, is monitoring of primary to secondary leakage through the steam generators. Leakage that is still within allowable limits can be monitored and a determination regarding timing of shutdown and repair of steam generator tubes can be made.

FSAR Supplement: Because the reactor coolant system operational leakage monitoring program is not a new program and currently is described in the McGuire and Catawba Technical Specifications, the staff finds that there is not a need to include the program description in the FSAR.

In conclusion, the staff finds that the Reactor Coolant System Operational Leakage Monitoring program has been demonstrated to be capable of providing an additional line of defense against aging effects that may result in leakage due to cracking and loss of mechanical closure integrity. Based on the staff's review, the continued implementation of the Reactor Coolant System Operational Leakage Monitoring Program provides reasonable assurance that the aging effects will be managed and that the reactor coolant pressure boundary will continue to perform its intended function for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.3.3 Conclusions

The staff reviewed the information included in Section 3.1.1 of the LRA, as supplemented by the April 15, 2002, response to the RAI. On the basis of its review, with the exception of open item 3.1.3.2.2-1 pertaining to the Reactor Vessel Integrity program and open item 3.1.3.2.2-2 pertaining to the VHP Nozzle program, the staff concludes that the applicant has demonstrated that the aging effects associated with the RV and CRDM pressure boundary components will be adequately managed so that there is reasonable assurance that these components will perform their intended function(s) consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.4 Reactor Vessel Internals

The reactor vessel (RV) internals consist of three parts: the lower core support structure, the upper core support structure, and the in-core instrumentation support structure. The lower core support structure consists of the core barrel; the core baffle; the lower core plate and support columns; the neutron shield pads; and the core support which is welded to the core barrel. The lower core support structure is supported at its upper flange from a ledge in the reactor vessel and its lower end is restrained from transverse motion by a radial support system attached to the vessel wall. The upper core support structure, which is removed as a unit during refueling, consists of the upper support assembly and the upper core plate, between which are contained the upper head injection (UHI) support columns and guide tube assemblies. The upper core support assembly is positioned in its proper orientation with respect to the lower support structure by slots in the upper core plate which engage the upper core plate alignment pins. The in-core instrumentation support structures consist of an upper system to convey and support thermocouples penetrating the vessel through the head and a lower system to convey and support flux thimbles penetrating the vessel through the bottom.

The RV internals support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between fuel assemblies and control rod drive mechanisms, direct coolant flow past the fuel elements, direct coolant flow to the pressure vessel head, provide gamma and neutron shielding, and provide guides for the in-core instrumentation.

As described in Section 4.2.2 of McGuire UFSAR and Section 3.9.5 of Catawba UFSAR, the design and operating characteristics of the RV internals for McGuire and Catawba are identical, with the following exceptions. For McGuire, the upper head injection (UHI) upper internals assembly originally provided passage for the UHI accumulator water from the vessel head plenum directly to the top of the fuel assemblies during a LOCA. The UHI accumulator has been removed from service by capping the injection piping at the top of the vessel head. The UHI internals were not modified. For the Catawba, the UHI upper internals assembly provide passage for the core cooling water from the vessel head plenum directly to the top of the fuel assemblies during the postulated LOCA.

3.1.4.1 Technical Information in the Application

The applicant described its AMR of the RV internals for license renewal in Section 3.1.1 of the LRA, "Aging Management Review Results Tables," as supplemented by the applicant's responses to the RAIs 3.1.4-1 through 3.1.4-4 and RAIs B.3.27-1 and B.3.27-2, all dated April 15, 2002. The staff reviewed this section of the LRA to determine whether the applicant had demonstrated that the effects of aging on the RV internals will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

RV internals are fabricated from stainless steel, with the exception of the irradiation specimen holder spring and the lower core support structure clevis inserts and fasteners, which are fabricated from a nickel-based alloy. Table 3.1-1 of the LRA, identifies a small number of the stainless steel RV internals made from CASS. These are the upper support column (including the base, conduit support, thermocouple stop(U1)), the 15x15 and 17x17 guide tube assembly, the UHI flow columns (base), and the bottom-mounted instrumentation (upper end, cruciform).

The RV internals are immersed in borated reactor coolant water at a normal operating temperature of approximately 315 ^{o}C (600 ^{o}F). In the core region, they are also exposed to high neutron fluence.

3.1.4.1.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identifies that the following aging effects are generally applicable to the RV internals requiring AMRs:

- cracking
- loss of material
- loss of preload
- reduction in fracture toughness
- dimensional changes

3.1.4.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant identifies the following AMPs applicable to the McGuire and Catawba RV internals:

- chemistry control program
- ISI plan
- Alloy 600 aging management review
- reactor vessel internals inspection

The applicant concluded that these AMPs will manage the effects of aging such that the intended function of the RV internals will be maintained consistent with the CLB under all design loading conditions throughout the period of extended operation, as required by 10 CFR 54.21(a)(3). Table 3.1-1 narrows in scope which of these programs will be used to manage the aging effects identified in the table as being applicable to the specific RV internal components requiring AMRs.

The applicant did not specifically identify any TLAA in Section 3.1.1 of the LRA that is applicable to RV internals. However, Section 4.3 of the LRA includes a TLAA for metal fatigue of ASME Class 1 components that applies to RV internals.

3.1.4.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.1 (including Table 3.1-1) of the LRA and pertinent sections of Appendices A and B to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended function(s) of the RV internals will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

In Table 3.1-1 of the LRA, the applicant states that the intended functions of the RV internals to provide support and orientation of the reactor core (i.e., the fuel assemblies); provide support, orientation, guidance and protection of the control rod assemblies; provide a passageway for the distribution of the reactor coolant flow to the reactor core; provide a passageway for support, guidance, and protection for the incore instrumentation; provide secondary core support for limiting the downward displacement of the core support structure in the event of a postulated failure of the core barrel; and provide neutron shielding of the reactor vessel and provide support for vessel material test specimens.

3.1.4.2.1 Aging Effects

In accordance with Section 3.1 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the RV internals components to provide reasonable assurance that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for Catawba and McGuire. This also included the plant-specific operating experience at both subject plants.

LRA Table 3.1-1 lists the RV internals, intended functions, materials of construction, operating environment, aging effects, and aging management programs and activities credited to manage the identified aging effects for each RV internal component category. A review of the information in this table indicates that all applicable RV internals are identified, except for the BMI instrumentation tubes. The applicant has grouped the BMI instrumentation tubes with the RV and CRDM pressure boundary components.

The materials of construction for the RV internals are stainless steel, including CASS, and nickel-based alloy. All surfaces of RV internals are exposed to borated water. Table 3.1-1 of the LRA identifies the following aging effects requiring aging management:

- cracking of stainless steel (including cast austenitic stainless steel) and nickel-based alloy components in a borated water environment

- loss of material from stainless steel (including cast austenitic stainless steel) and nickel-based alloy components in a borated water environment
- reduction in fracture toughness of stainless steel and cast austenitic stainless steel in a borated water environment
- loss of preload of stainless steel bolting and hold down springs in a borated water environment
- dimensional changes of stainless steel components in a borated water environment due to void swelling

As described in topical report WCAP-14577, Rev. 1-A, “License Renewal Evaluation: Aging Management for Reactor Internals,” and the associated staff FSER, the aging mechanisms potentially applicable to the RV internals are neutron irradiation embrittlement, stress corrosion cracking (SCC), irradiation-assisted stress corrosion cracking (IASCC), erosion and corrosion processes, creep/irradiation creep, stress relaxation, wear, thermal aging, fatigue, and void swelling. However, the RV internals at McGuire and Catawba are made from materials that are resistant to loss of material by general corrosion and flow-assisted corrosion (erosion/corrosion). The RV internals for the McGuire and Catawba units also are not exposed to a high enough temperature (>540^{o}C or 1000 of) where creep-induced degradation would become an aging concern for the internals.

Cracking of RV internals due to either stress corrosion cracking (SCC) or irradiation-assisted stress corrosion cracking (IASCC) is an applicable aging effect for RV internals. SCC results from the synergistic effects of tensile stresses and a corrosive environment on a susceptible material. SCC is a particular concern for bolting, given the potential for occluded environmental conditions in crevice areas. IASCC is SCC that is enhanced by exposure of the materials to ionizing radiation. Cracking of the RV internals may also occur be thermal fatigue. The applicant addresses thermal fatigue of the RV internals in Section 4.3 of the LRA. The staff evaluates thermal fatigue of the RV internals in Section 4.3 of this SER. In LRA Table 3.1-1, the applicant has identified cracking as an applicable aging effect for all RV internals. This is acceptable to the staff because the applicant has accounted for cracking of the RV internals that could be induced by either SCC, IASCC, or thermal fatigue.

Loss of material from wear of RV internals occurs due to relative motion between the interfaces and mating surfaces of components caused by flow-induced vibration during plant operation; differential thermal expansion and contraction movements during plant heatup and cooldown; and changes in power operating cycles. The severity of the wear depends on the frequency of motion, duration, and component loadings. Although the applicant did not discuss wear in LRA Section 3.1, the applicant did identify loss of material as an applicable aging effect for all RV internals in Table 3.1-1 of the application. This is acceptable to the staff because it agrees with NUREG-1800 that loss of material is an applicable effect for the RV internals of PWRs and because it specifically accounts for loss of material that could be induced by wear.

Stress relaxation may be defined as the unloading of preloaded components under conditions of long-term exposure of RV internals materials to high constant strain, elevated temperature, and/or neutron irradiation. Loss of preload due to stress relaxation is an applicable aging effect for those RV internals with substantial preload (e.g., hold down spring, bolted connections). A loss of preload in these components could result in higher cyclic and transient loads, and a loss of function. The combination of bolt stress relaxation, changes in transient and high-cycle vibration of the RV internals, and the effects of increased RV internals fatigue susceptibility may be significant for the license renewal period. The RV internals susceptible to loss of preload due to stress relaxation are the upper and lower support column bolts, the hold down spring, and the clevis insert bolts. In LRA Table 3.1-1, the applicant has identified loss of preload as an applicable aging effect for the upper and lower support column bolts and the hold down spring, but not for the clevis insert fasteners.

By letter dated January 30, 2002, the staff informed the applicant that WCAP-14577, “License Renewal Evaluation: Aging Management for Reactor Internals,” specifically identifies that loss of preload is an applicable effect for the clevis insert bolts (fasteners) during normal operations and requested (in RAI 3.1.4-4) the applicant to address this information from the WCAP. In its response to RAI 3.1.4-4, dated April 15, 2002, the applicant stated that loss of preload could be an applicable effect for the McGuire and Catawba clevis insert fasteners, and that the effects of loss of preload in the clevis insert fasteners would manifest itself as loose, cracked, or missing clevis inserts bolts (fasteners). The applicant stated that, since a VT-3 examination may not be sufficient to detect cracking, the applicant will perform a VT-1 examination of the clevis insert fasteners each inspection interval. In the response to RAI 3.1.4-4, the applicant provided a supplemental AMR Table for the clevis insert fasteners that adds loss of preload as an applicable effect for the clevis insert fasteners (in addition to cracking and loss of material). The staff’s evaluation of the applicant’s proposed augmented inspection activities for the clevis insert fasteners is given in Section 3.1.4.2.2 of this SER.

The applicant’s response to RAI 3.1.4-4 and supplemental AMR for the clevis insert fasteners identifies that loss of preload is an additional aging effect for the RV internals upper and lower support column bolts, hold down spring, and clevis insert fasteners. This is acceptable to the staff because it accounts for stress relaxation, which is contributing cause of loss of preload in these components, and because it agrees with Table 3.1-1 of NUREG-1800 that loss of preload is an applicable aging effect for bolted, fastened, or spring loaded RV internals in PWR-designed reactors.

In LRA Section 3.1.1, the applicant states that reduction in fracture toughness due to thermal embrittlement can be an aging effect for certain types of CASS components in locations where temperatures continuously exceed 250^{o}C (482^{o}F). The staff, in a letter dated May 19, 2000, clarified that not all CASS materials are subject to thermal embrittlement and provided certain criteria for identifying CASS components susceptible to thermal embrittlement. In this letter the staff specifically identified that centrifugally cast CASS materials are not subject to thermal aging in the manner that statically cast CASS materials are. Neutron irradiation of CASS materials may also contribute a loss of fracture toughness in the materials if the exposure to the neutrons is above a certain threshold. The applicant stated that it performed an analysis of all CASS material components in the RCS. As a result of this analysis, the applicant identified that reduction in fracture toughness is an applicable aging effect for all RV internals made out of CASS. This is acceptable to the staff because it accounts for the effect of ionizing irradiation of the fracture toughness properties of CASS RV internals, and because it agrees with Table 3.1-1 of NUREG-1800 that loss of fracture toughness is an applicable aging effect for all PWR RV internals made from CASS.

The RCCA guide tube support pins used in Westinghouse RV internals have a history of degradation. Several Westinghouse plants experienced cracking of guide tube support pins manufactured from Alloy X-750. The cracking of the Alloy X-750 material was attributed to the combination of high stress and undesirable microstructure. In WCAP-14577, Rev. 1-A, Westinghouse stated that cracking of the support pins will not result in a significant misalignment and the intended function will be maintained. However, these pins are being replaced at a number of plants. Replacement is considered to be a sound maintenance practice to preclude degradation when industry experience indicates that such degradation has been observed. In Table 3.1-1 of the LRA, the applicant does not list the RCCA guide tube support pins as a separate entry. By letter dated January 28, 2002, the staff requested, in RAI 3.1.4-1, clarification of the aging management for these components at McGuire and Catawba. In its response dated April 15, 2002, the applicant indicated that the guide tube support pins, “split pins,” are part of the guide tube assemblies in Table 3.1-1 (page 3.1-16, row 3) of the LRA. The applicant has stated that since the guide tube support pins (split pins) are fabricated from Type 316 cold worked stainless steel, they have the same aging effects applicable to the other stainless steel components in the guide tube assemblies. This is acceptable to the staff because it agrees with Table 3.1-1 of NUREG-1800 that loss of material and cracking are both applicable effects for these components.

In LRA Table 3.1-1, the applicant did not identify reduction in fracture toughness due to irradiation as one of the applicable aging effects for the lower support plate (forging) and lower core support column reactor vessel internals. These materials are fabricated from austenitic stainless steel. In NUREG/CR-6048, Oakridge National Laboratory, on behalf of the NRC, has used 5×10^{20} neutrons/cm^2 (E > 1 MeV) as the threshold for loss of fracture toughness due to radiation embrittlement in Type 304 austenitic stainless steel materials. To substantiate that loss of fracture toughness is not an applicable effect for these components, the staff issued RAI 3.1.4-2, by letter dated January 28, 2002, and requested that the applicant confirm that accumulated neutron fluence (E > 1 MeV) for these components during the period of extended operation would be lower than this threshold for radiation induced embrittlement. In the RAI, the staff also indicated that, if the fluence levels for the lower support plate (forging) and lower core support columns were projected to be greater than 5×10^{20} neutrons/cm^2 (E > 1 MeV), the applicant should discuss how reduction in fracture toughness in these components would be managed during the proposed extended periods of operation.

In its response to RAI 3.1.4-2, dated April 15, 2002, the applicant stated that the maximum projected fluence for the lower support forging at 54 ESPY is approximately 5×10^{18} neutrons/cm^2 (E > 1 MeV) which is less that the threshold fluence value established by the staff. The applicant stated that the lower support forging is not expected to experience reduction of fracture toughness as a result of neutron embrittlement. In contrast, the applicant also stated that the maximum projected fluence at the very top of the lower core support columns, the area of the columns closest to the core and subject to the highest neutron fluence, is approximately 5×10^{21} neutrons/cm^2 (E > 1 MeV), and that, because the projected fluence at the top portion of the support columns is projected to exceed the threshold 5×10^{20} neutrons/cm^2 (E > 1 MeV), reduction in fracture toughness should be included as an aging effect for the lower core support columns. The applicant also stated that this aging effect will be managed by the RV internals inspection program (Section B.3.27 of Appendix B to the LRA). On the basis of this evaluation and in response to RAI 3.1.4-2, the applicant provided a supplemental AMR for the lower core support columns that added reduction of fracture toughness as an applicable aging effect for the lower core support columns. This is acceptable to the staff because it is in agreement with Table 3.1-1 of NUREG-1800 that loss of fracture toughness due to neutron irradiation is an applicable effect for RV internals within the fuel zone region of the reactor (i.e., within regions of the reactor that amass high neutron fluence dose rates).

Void swelling is defined as a gradual increase in dimensions of the RV internals. Under reactor internals irradiation conditions, helium is generated as a nuclear transmutation reaction product. At sufficiently high temperatures, helium bubbles expand to a critical diameter and coalesce (unite) into larger bubbles. These bubbles create void areas (gaps) in the materials and may result in the swelling of the material. Swelling changes the dimensions of the material and may affect the ability of the particular RV internal component to perform its intended functions. Although void swelling has not been observed to date, the staff is concerned that void swelling may become significant during the period of extended operation. Until industry has developed sufficient data to demonstrate that void swelling is not a significant aging mechanism, the staff believes that void swelling should be considered significant, and applicants for license renewal should describe their aging management plan to address void swelling. In LRA Table 3.1-1, the applicant has identified change in dimension as an applicable aging effect for some of the RV internals, presumably those exposed to the highest neutron fluence. By letter dated January 28, 2002, the staff requested, in RAI 3.1.4-3, additional information concerning the criteria applied to establish which RV internals are susceptible to change in dimension due to void swelling.

In its response to RAI 3.1.4-3, dated April 15, 2002, the applicant stated that uncertainty currently exists relative to the prediction of void swelling in pressurized water reactor conditions. This uncertainty is based on the fact that existing swelling data has been obtained from materials that were not irradiated in a pressurized water reactor environment. Void swelling is a complex function of neutron flux, neutron fluence, operating temperature, operating stress, material composition, and material fabrication process. However, the key environmental factors influencing void swelling are cumulative radiation dose and temperature.

At present, data are not available to ascertain a specific threshold for the onset of void swelling in solution annealed Type 304 stainless steel in a pressurized water reactor environment. However, the onset of void swelling in solution annealed and 10, 20, 30 percent cold worked Type 304 stainless steel exposed to a breeder reactor environment is available, and is estimated to start at fluence levels of approximately 4 to 8 x 10^{22} neutrons/cm^2 (E > 1 MeV) at a temperature of 440^{o}C (824^{o}F) (Effects of Radiation on Materials, ASTM STP725, Comparison of High-Fluence Swelling Behavior of Austenitic Stainless Steels, Page 484)Pressurized water reactors operate at approximately 315^{o}C (599^{o}F) well below 440^{o}C (824^{o}F). Duke conservatively estimated all reactor vessel internal components, which receive greater than 10^{22} neutrons/cm^2 (E >1 MeV), as having the potential for void swelling as an aging effect.

At the time LRA was being prepared, the reactor vessel internals locations identified in Table 3.1-1 as susceptible to dimensional changes were considered to be the limiting locations. However, based on a fluence analysis that has been recently completed, several of these locations are no longer considered to be limiting. The locations that are no longer considered to be limiting are the core barrel flange, outlet nozzles, neutron panels, irradiation and specimen holder fasteners. These locations do not fall within that range of fluence identified above and should not have dimensional change due to void swelling as an aging effect during the license renewal period.

Understanding the factors discussed above requires further assessment of the operating conditions experienced in pressurized water reactors and how stainless steel responds under these conditions. Duke is currently participating in industry programs which are addressing the significance of void swelling. These programs are addressing both the physical phenomena of void swelling, as well as the safety significance. As understanding of the phenomenon of void swelling increases, Duke will adjust programmatic management of the RV internals as needed to ensure that there remains reasonable assurance that there is not a loss of intended function during the period of extended operation, due to void swelling. The RV internals inspection (Section B.3.27 of Appendix B to the LRA) identifies the applicant’s committed actions with respect to identification and inspection of the most susceptible (limiting) RV internals to void swelling, including participation in the industry’s program to address this issue. The staff’s evaluation of this AMP is documented in Section 3.1.4.2.2 of this SER.

Westinghouse WCAP-14577, Rev. 1-A, “License Renewal Evaluation: Aging Management for Reactor Internals,” defines fatigue as the structural deterioration which results from repeated stress/strain cycles due to fluctuating loads and temperatures. Following repeated cyclic loading of sufficient magnitude, damage can accumulate, initiating a crack in highly affected locations. As described in the topical report, the design bases for many Westinghouse RV internals include explicit fatigue evaluations. This is the case not only for RV internals designed to the ASME Boiler and Pressure Vessel Code, Section III, Subsection NG, 1974 Edition, but also for RV internals designed using the ASME Code as a guide, prior to incorporation of Subsection NG in the code. The McGuire and Catawba RV internals were designed before the incorporation of Subsection NG in the 1974 ASME Code. LRA Section 4.3 describes the applicant’s TLAA for metal fatigue. The staff’s evaluation of the TLAA for metal fatigue is given in Section 4.3 of this SER.

On the basis of the description of the internal and external environments, materials used, and the applicant's review of industry and plant-specific experience, the staff concludes that the applicant has identified all aging effects that are applicable for the RV internals.

3.1.4.2.2   Aging Management Programs

In Table 3.1-1 of the LRA, the applicant credits the following AMPs to manage aging of the RV internals:

- chemistry control program
- ISI plan
- Alloy 600 aging management review
- reactor vessel internals inspection

In Table 3.1-1 of the LRA, the applicant lists all RV internals components within the scope of the license renewal with their intended functions, material groups, and environment. Also, the table identifies the aging effects requiring management and the plant-specific AMPs required to manage these aging effects during the period of extended operation.

The chemistry control program (Section B.3.6 of Appendix B to the LRA) provides water quality that is compatible with the materials of construction used in McGuire and Catawba RV internal components in order to minimize loss of material and cracking. This program is developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for RV internals. The staff’s evaluation of this AMP is documented in Section 3.0 of this SER.

The ISI plan (Section B.3.20 of Appendix B to the LRA) manages aging effects of loss of material, cracking, gross loss of preload, and gross reduction in fracture toughness. The scope of the ISI plan for Class 1 components complies with the requirements of ASME Section XI, Subsections IWB. Depending on the examination category, the methods of inspections may include visual, surface and/or volumetric examination of weld locations susceptible to aging degradation. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the reactor vessel internals. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

In its response to RAI 3.1.4-4, the applicant identified that loss of preload was an applicable aging effect for the RV internals clevis insert fasteners and stated that the ISI plan will be augmented to manage loss of preload in the RV internals clevis insert fasteners. Therefore, the applicant stated that the following will be added to both Section 18.2.16 of the FSAR Supplement for the McGuire station and Section 18.2.15 of the FSAR Supplement for the Catawba station:

> A VT-1 examination of the reactor vessel internal clevis insert fasteners will be performed in lieu of the VT-3 examination currently required by ASME Section XI.

This statement supplements the [Monitoring and Trending] program attribute for the ISI plan (Section B.3.20 of Appendix B to the LRA). The staff concludes that the proposal to use a VT-1 examination of the clevis insert fasteners once an ISI interval in lieu of a VT-3 examination is acceptable because the requirements imposed by ASME Section XI for performing VT-1 type visual examinations are more conservative than those imposed by ASME Section XI for performing VT-3 type visual examinations. The applicant's method for inspecting the clevis insert fasteners during the extended periods of operation is therefore acceptable to the staff.

As it relates to RV internals, the purpose of the Alloy 600 aging management review, as described in Appendix B.3.1 of the LRA, is to ensure that nickel-based alloy locations are adequately inspected for cracking due to PWSCC by the ISI plan and the reactor vessel internals inspection. This review will be completed after issuance of a renewed operating license, but before June 12, 2021 for McGuire and before December 6, 2024 for Catawba. The staff has evaluated this AMP and found it to be acceptable for managing the aging effects identified for RV internals. The staff's evaluation of the Alloy 600 aging management review is documented in Section 3.1.2.2.2 of this SER.

The Reactor Vessel Internals Inspection, as described in Appendix B.3.27 of the LRA, manages cracking due to IASCC and SCC, reduction in fracture toughness due to irradiation and thermal embrittlement, dimensional changes due to void swelling, and loss of preload due to stress relaxation. The staff's evaluation of this program follows.

<u>Reactor Vessel (RV) Internals Inspection</u>

The applicant describes the Reactor Vessel Internals Inspection program in Appendix B.3.27 of the LRA. The applicant credits this AMP to manage specific RV internals aging effects for McGuire and Catawba. The staff reviewed the applicant's description of the program to determine whether the applicant had demonstrated that it will adequately manage the applicable effects of aging in applicable RV internals during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The purpose of the reactor vessel internals inspection is to monitor the condition of RV internals in order to assure that the applicable aging effects will not result in loss of their intended functions during the period of extended operation. The applicant identifies three groups of stainless steel RV internals within the scope of this AMP: (1) plates, forgings and welds; (2) baffle-to-baffle, baffle-to-former, and barrel-to-former bolting; and (3) items fabricated from CASS. The applicant stated that different aging effects will affect various RV internal parts. The aging effects addressed by this AMP are: (1) cracking, (2) loss of preload, (3) reduction in fracture toughness, and (4) dimensional changes. The applicant stated that this AMP will supplement the ISI plan to assure that aging effects potentially requiring additional management will not result in loss of intended functions of the RV internals during the period of extended operation.

Table 3.1-1 of the LRA identifies that the RV internals that will be managed by AMP B.3.27 are CASS upper support column (base, conduit support, thermocouple stop(U1)); upper support column bolts; upper core plate and its alignment pins; fuel alignment pins; CASS 15x15 and 17x17 guide tube assembly; CASS UHI flow columns (base); core barrel, flange and outlet nozzles, neutron panels, irradiation specimen holder fasteners; baffle and former plates; baffle bolts; lower core plate, fuel alignment pins, lower support column bolts; and CASS bottom-mounted instrumentation (upper end, cruciform).

The applicant credited the McGuire/Catawba RV Internals Inspection for managing aging effects in the McGuire/Catawba RV internal components. The staff evaluated the RV Internals Inspection on the following seven program attributes for the program:

1. Scope of Program
2. Preventative Actions
3. Parameters Monitored or Inspected
4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria
7. Operating Experience

The staff's evaluations of these program attributes are given in the paragraphs that follow. The staff's evaluation of the other three program attributes (confirmatory actions, corrective actions, and administrative controls) for the RV Internals Inspection is documented in Section 3.0.4 of this SER.

[Program Scope] The applicant stated that the scope of this AMP consists of three groups of stainless steel RV internals: (1) items comprised of plates, forgings, and welds, (2) bolting (baffle-to-baffle, baffle-to-former, and barrel-to-former), and (3) items fabricated from CASS. Note that the applicant has proposed to use an augmented ISI plan VT-1 examination as the method for managing of loss of preload in the clevis insert fasteners in lieu of the RV internals inspection. The staff's evaluation of the augmented ISI examination method for managing loss of preload in the clevis insert fasteners is given in Section 3.1.4.2.2 of this SER. The staff concludes that the applicant's scope for the RV Internal Program identifies the appropriate RV internal components needing aging management by the program.

[Preventive Actions] The applicant stated that there are no preventive/mitigative actions associated with this program, nor did the staff identify a need for such. The reactor vessel internals inspection is a surveillance monitoring program and, as such, is not designed to prevent or mitigate the aging effects for the RV internal components prior to their occurrence. Since the RV internals inspection is not a preventative or mitigative aging management program, the staff concludes that the [Preventative Actions] program attribute for the RV internals inspection is acceptable.

[Parameters Monitored or Inspected] The program requires the applicant to perform visual inspections of the RV internals components for the purpose of detecting loss of material due to wear or cracking initiated by fatigue, SCC or IASCC. Visual inspections will also be performed to detect dimensional changes induced by void swelling. Volumetric inspection of bolting is performed to detect IASCC. The RV internals inspection requires the applicant to inspect CASS or highly irradiated stainless steel RV internals components for cracks to ensure that the components will not fail catastrophically as a result of fast fracture. The staff concludes that the [Parameters Monitored or Inspected] attribute for the RV Internals Inspection is acceptable because the program directly monitors for flaws (cracking and loss of material) that may occur in the RV internal components and because the program indirectly monitors for materials and mechanical property changes (i.e., for materials/mechanical property-related aging effects of loss of fracture toughness, void swelling, and loss of preload) that may occur in the internals. In the case of the later, the program accomplishes this by ensuring the cracks are detected prior to growth above a limiting size, by monitoring for dimensional changes in RV internal components, and by monitoring for loose or displaced RV internal components, respectively.

[Detection of Aging Effects] The applicant stated that the RV internal program uses visual and volumetric inspection methods to monitor for flaws (cracking and loss of material) in the RV internal components. The program also indirectly monitors for materials and mechanical property changes (i.e., for materials/mechanical property-related aging effects of loss of fracture toughness, void swelling, and loss of preload) by ensuring the cracks are detected prior to growth above a limiting size, by monitoring for dimensional changes in RV internal components, and by monitoring for loose or displaced RV internal components. In accordance with the ISI plan, ISI Examination Category B-N-3, for removable core support structures, is directly applicable to the RV internals. This requires visual VT-3 examination of all accessible parts of the RV internals. Cracks initiated by stress corrosion cracking or fatigue will start off very small and will grow over time. VT-3 visual examinations may not be adequate for detecting cracks before they reach the critical flaw size. The monitoring and trending section of this program, which describes the inspection activities for various types of RV internals, indicates that a visual inspection will be performed on components fabricated from plates, forgings and welds to detect the effects of cracking. By letter dated January 30, 2002, the staff requested, in RAI B.3.27-2, the applicant to indicate which visual inspection method (VT-1, VT-2 or VT-3) will be used so that the staff can determine if the visual inspection activities will be capable of detecting cracks before a critical flaw size is reached, and that if VT-3 is proposed as the inspection method, to justify the use of this method for identifying small cracks, or describe enhancements planned to augment this inspection activity.

In its response to RAI B.3.27-2 dated April 15, 2002, the applicant stated that the reactor vessel internals inspection is a program that is completely separate from the ISI plan. As described in Section B.3.27 of the LRA, the RV internals inspection is being developed to supplement the ISI plan and is separate from the VT-3 visual examinations currently required by examination category B-N-3. The applicant also stated that the RV internals inspection includes several inspections and examinations. The applicant stated that items comprised of plates, forgings, and welds that will be visually inspected, the critical crack size will be determined by analysis and the acceptance criteria for all aging effects will be developed prior to the inspection. The applicant stated that the visual inspection method will be sufficient to detect the critical crack size determined by analysis.

For inspections of baffle bolts, the applicant stated it will perform volumetric examinations to detect whether cracking has occurred in the bolts. As discussed in the staff's FSER for Westinghouse WCAP-14577, Rev. 1-A, "License Renewal Evaluation: Aging Management for Reactor Internals," visual examinations will not detect cracking in these bolts. Industry experience is that the cracks will form under the head of the bolts, which is not accessible for visual examination. In addition, loose parts monitoring and coolant reactivity monitoring are effective only after the aging effects have manifested themselves is a potentially serious way. Therefore, augmented inspections, such as ultrasonic examinations, are proposed to provide effective aging management. This is acceptable since the method will be capable of detecting cracks under the heads of the bolts that would not necessarily be detected by use of visual examination methods.

Neutron embrittlement and thermal aging are two mechanisms that may reduce the fracture toughness for a given material. Reduction in fracture toughness lowers the material's critical crack size, which is a bounding material property for any given material. When cracks exist in a component and grow to sizes larger than the critical crack size for the component's material of fabrication, the cracks are considered to be unstable and will propagate quickly through the component. This phenomenon is referred to by materials and mechanical engineers as crack growth by fast fracture. Cracks that propagate unstably by this phenomenon may lead to catastrophic failure of the component. CASS components are known to be particularly susceptible to reduction in fracture toughness as a result of thermal aging; neutron embrittlement of CASS internals may enhance this effect. When this occurs, a CASS component's tolerance to withstand the presence of existing flaws (cracks) is significantly reduced. Thus, while the RV internals inspection will not be capable of detecting the critical crack size for the RV internal components made from CASS materials (i.e., because the critical crack size is a material property, not an actual crack or flaw in the material), the examination is designed to detect potential cracks in the RV internals prior to their growing to a size greater than the critical crack size for the material (i.e., critical crack size as reduced as a result of loss of fracture toughness in the material). The applicant has stated that the critical crack size for the CASS RV internals will be established by engineering analysis or calculation, which is the typical method of determining the critical crack size for a given material. Given the applicant's response to RAI B.3.27-2, the applicant must select an examination method that can actually characterize the sizes of potential cracks in the CASS RV internals and must perform the examination prior to entering the periods of extended operation. When assessed from these technical bases, the applicant's parameters monitored or inspected program attribute is acceptable to the staff.

In electronic correspondence, dated June 5-6, 2002 (ADAMS Accession Number not yet available), the staff asked the applicant to clarify the last sentence of the second paragraph of its response to RAI B.3.27-2. This clarification would be reflected in the [Detect of Aging Effects] program attribute for this program that is provided in FSAR Supplement Chapter, Section 18.2.22. The applicant agreed to make this clarification. By letter dated July 9, 2002, the applicant provided the following:

> Duke confirms that the intent of the last sentence in the second paragraph of its response should be clarified to state:
>
>> The visual inspection method selected for the inspection of RV internal plates, forging, and welds will be sufficient to detect cracks in the components prior to any growth to a size that is greater than the critical crack size (critical crack length) for the material.

Therefore, this issue is resolved.

[Monitoring and Trending] The applicant stated that the Reactor Vessel Internals Inspection includes the following inspection activities: (1) for plates, forgings, and welds, a visual inspection will be performed to detect the effects of cracking by irradiation assisted stress corrosion cracking enhanced by reduction of fracture toughness by irradiation embrittlement; (2) for baffle bolts, a volumetric inspection will be performed at McGuire 1 to assess cracking; and (3) for items fabricated from CASS, an analytical approach to assess the effect of reduction of fracture toughness on the applicable reactor vessel internals items will be performed. The applicant stated that the specific inspection method will depend on the results of these analyses. The applicant stated that the inspections of RV internals at McGuire 1 will be performed in the fifth ISI interval. The decision to perform inspections on McGuire 2, Catawba 1, and Catawba 2 and when to perform such inspections will depend on an evaluation of the results of the internals inspections performed at Oconee and on McGuire 1.

The applicant also stated that, with respect to dimensional changes due to void swelling, McGuire and Catawba will rely on the results of inspections to be performed at Oconee, and that Items comprised of plates, forgings, and welds will be inspected at all three Oconee Units to assess the effects of void swelling. Activities are in progress to develop and qualify the inspection method. The applicant stated the results of the Oconee inspections will be used to determine if change in dimensions due to void swelling is a concern for the reactor vessel internals of McGuire 1, McGuire 2, Catawba 1, and Catawba 2, and if additional inspections are necessary. Should industry data or other evaluations indicate that the above inspections can be modified or eliminated, Duke will provide plant-specific justification to demonstrate the basis for the modification or elimination. In addition, the applicant stated that should industry data or other evaluations indicate that any of the above inspections can be modified or eliminated, Duke will provide plant-specific justification to demonstrate the basis for the modification or elimination. With regard to monitoring for dimensional changes to due void swelling, this is acceptable to the staff because the Oconee, McGuire and Catawba plants all have RV internals that are all made from martensitic stainless steel materials, austenitic stainless steel materials (including CASS), and Nickel-based alloy materials.

By letter dated January 28, 2002, the staff requested, in RAI B.3.27-1, the applicant to clarify the technical validity of this extrapolation, specifically with respect to the similarities and differences pertaining to RV internals design details; materials of construction; reactor power rating and neutron fluence levels; and critical locations where dimensional changes may compromise performance of intended functions. In its response dated April 15, 2002, the applicant stated that currently, limited data from pressurized water reactor internals are available to properly evaluate the potential for dimensional changes to occur as a result of void swelling. Additional data is needed to properly evaluate the most susceptible locations for inspections. The applicant stated that the Oconee RV internals inspections will provide some of that data prior to McGuire and Catawba license renewal period. Current plans are to inspect the Oconee Unit 1 internals for dimensional changes due to void swelling early in its twenty-year period of extended operation or about 2015. Based on the Oconee inspections as well as results from other internals inspections in the industry, the applicant stated that it will prepare the inspection plan for McGuire 1.

In the [Monitoring and Trending] attribute for the RV internals inspection AMP, the applicant stated it will perform a volumetric inspection of the McGuire 1 baffle bolts in the fifth ISI Interval and that any detectable cracks are considered to be unacceptable. The applicant also stated that the number of baffle bolts to be inspected and their locations will be determined by analysis. As discussed in the staff's FSER for Westinghouse WCAP-14577, Rev. 1-A, "License Renewal Evaluation: Aging Management for Reactor Internals," visual examinations will not detect cracking in these bolts. Industry experience is that the cracks will form under the head of the bolts, which is not accessible for visual examination. In addition, loose parts monitoring and coolant reactivity monitoring are effective only after the aging effects have manifested themselves is a potentially serious way. Therefore, augmented inspections, such as ultrasonic inspections, are needed to be proposed in order to provide effective aging management of the baffle bolts

In RAI 3.27-1, the staff questioned the validity that the results of the McGuire 1, and as well as the Oconee Unit 1, baffle bolt examinations would provide an acceptable basis for determining whether to schedule and perform corresponding baffle bolt examinations at McGuire 2 and Catawba 1 and 2. In its response to RAI B.3.27-1, the applicant also provided the following tabular comparison of the reactor power level, materials, operating temperatures and estimated peak fluence for the Oconee Unit 1, McGuire 1 and 2, and Catawba 1 and 2 baffle plate and bolt locations at the end of 40-year current licensing period:

Unit	**Reactor Power (MWt)**	**Baffle Former and Plate Material**	**Baffle Bolt Material**	T_{Hot}	T_{Cold}	**Estimated Peak Fluence at Baffle Plate and Bolt location (n/cm^2, E>1MeV) and year**
ONS 1	2568	Type 304 Stainless Steel	Type 304 Stainless Steel	602.4	557.8	4.5×10^{22} in 2015*
MNS 1	3411	Type 304 Stainless Steel	Type 316 Cold Worked	613.9	556.3	5.95×10^{22} in 2021**
MNS 2	3411	Type 304 Stainless Steel	Type 316 Cold Worked	613.9	556.3	5.8×10^{22} in 2024**
CNS1	3411	Type 304 Stainless Steel	Type 316 Cold Worked	613.9	556.3	5.7×10^{22} in 2025**
CNS2	3411	Type 304 Stainless Steel	Type 316 Cold Worked	616.7	558.3	5.8×10^{22} in 2026**

* Estimated fluence at the time of the first reactor vessel internals inspection at Oconee
** End of 40-year operating license for each unit

On the basis of this comparison, the applicant believes that the estimated peak neutron fluence levels for the McGuire and Catawba baffle bolts at the end of the 40-year operating terms for the units will be similar to the estimated peak neutron fluence levels for the Oconee Unit 1 baffle bolts at the time the Oconee Unit 1 baffle bolts are planned to be inspected (in 2015).

The McGuire, Catawba, and Oconee baffle bolts are all fabricated from austenitic stainless steel materials (Type 304 and Type 316 are both austentic stainless steel grades of materials) that have similar material properties. Since the McGuire, Catawba, and Oconee baffle bolts are all fabricated from austenitic stainless steel materials, and since the amassed end-of-current-operating-term neutron fluences values for the McGuire and Catawba baffle bolts are expected to be of an order and magnitude similar to that amassed for the Oconee Unit 1 baffle bolts at the time the Oconee Unit 1 baffle bolts will be inspected, the staff concludes that the volumetric examination results of the Oconee Unit 1 and McGuire 1 baffle bolts will be a prime indicator of the condition in the McGuire and Catawba baffle bolts and justify use of these examinations as the basis for proposing whether examinations of the baffle bolts at McGuire 2 and Catawba 1 and 2 are necessary during the extended periods of operation for the units. Based on these technical considerations, the staff concludes that the applicant has proposed an acceptable basis for scheduling and performing volumetric examinations the McGuire and Catawba baffle plates and that the [Monitoring and Trending] attribute, as it pertains to inspections of the McGuire and Catawba baffle bolts, is therefore acceptable.

For the McGuire and Catawba RV internals made from CASS (i.e., 15X15 and 17X17 guide tube assemblies, BMI tubes, and bases of the UHI flow columns), Duke proposes to use an analytical evaluation as the basis for inspecting these components for cracks. The purpose of the analytical evaluation is for calculation of the critical crack size for the components under service loading conditions and service-degraded material properties (i.e., loss of fracture toughness) and to determine the type of NDE needed to detect cracks in the components prior to fast fracture to failure. The applicant proposes to inspect the limiting CASS component at McGuire 1 in the fifth ISI Interval for the plant and to use the results of the examinations as the basis for proposing whether corresponding examinations are warranted of the CASS RV internals at McGuire 1 and Catawba 1 and 2. The applicant’s program and basis for inspecting the CASS RV internals at McGuire and Catawba is acceptable because the McGuire 1 reactor is expected to the limiting reactor with respect to neutron exposure and the results of the inspections of the CASS RV internal components at McGuire 1 will provide a prime indication of the condition these components and form an acceptable for determining whether equivalent inspections of the CASS RV internal components at McGuire 2 and Catawba 1 and 2 are necessary.

For the remaining RV internal plates, forgings, welds and bolts (i.e., core barrel bolts and thermal shield bolts), the applicant has proposed to use examinations performed at Oconee Unit 1 and McGuire 1 as the basis for determining whether additional, corresponding examinations need to be scheduled and performed at McGuire 2 and both Catawba units. By letter dated June 26, 2002, the staff informed the applicant that its program for inspecting for these RV internal plates, forgings, welds and bolts was inconsistent with Duke Power Company’s corresponding program for the Oconee Nuclear Station, in which the applicant had proposed to inspection these components in all three reactor units of the station. In its response dated July 9, 2002, the applicant stated that the justification for using inspections of the McGuire 1 welded plates and forgings, welds and bolts (i.e., core barrel bolts and thermal shield bolts) was based on a determination that McGuire 1 was the most susceptible unit with regard to aging of RV internals at McGuire and Catawba. The applicant also stated that the decision to use inspections at Oconee 1 as an additional basis for scheduling inspections of the RV internals at McGuire 2 and Catawba 1 and 2 was based on the fact that the RV internals would be inspected prior to the time that any of the McGuire and Catawba units would enter their respective periods of extended operation.

Aging of RV internal components is dependent on a number of factors including amassed neutron irradiation dose, internal RV operating temperature, and stress and/or pressure loadings. Fabrication factors are also relevant for welded RV internals. The design fabricator of the RVs for McGuire 1 and Catawba 2 is not the same as the design fabricator for McGuire 2 and Catawba 1 or the design fabricator for the reactor units of the Oconee Nuclear Station. The McGuire 1 and Catawba 2 reactor vessels were designed, welded, and fabricated by the Combustion Engineering Corporation. The McGuire 2 and Catawba 1 reactor vessels were designed, welded, and fabricated by the Rotterdam Drydock. The reactor vessels for Oconee Units 1, 2, and 3 were designed, welded, and fabricated by the Babcock and Wilcox Corporation. For welded RV internal components, differences in welding techniques (including differences in use preheat methods or post-weld heat treatment methods, differences in welding fabrication methods, variations in the type of weld fluxes used, etc.) that are used to fabricate the vessels and their internal components can create a significant variation as to the susceptibility of the components to crack. The staff concludes that since the fabricator for the McGuire 1 and Catawba 2 RVs is not the same as the design fabricators for McGuire 2 and Catawba 1 RVs or for the Oconee RVs, some uncertainty exists whether the inspections of welded RV internals at Oconee Unit 1 and McGuire 1 will be truly representative of the condition of welded RV internals at McGuire 2 and the Catawba units. The staff's position is that the applicant should schedule inspection of remaining RV internal plates, forgings, welds and bolts (i.e., core barrel bolts and thermal shield bolts) at all of the McGuire and Catawba reactor units. Therefore, this issue is characterized as open item 3.1.4-1(a).

[Acceptance Criteria] The applicant stated that the acceptance criteria will be based upon analyses and inspections. The applicant stated that the critical crack size for RV internal plates, forgings, and welds, and RV internals made from CASS will be determined by analysis before inspection. For RV internal baffle bolts any detectable cracking on baffle bolts will be unacceptable. The number of baffle bolts needed to be intact and their locations will be determined by analyses. The applicant did not provide any acceptance criteria is provided for the dimensional change effects that could be induced by void swelling. The applicant's acceptance criteria for the RV internals inspection program is incomplete. The staff therefore needs additional information regarding the acceptance criteria for the inspections that are proposed to the RV internals. This issue is characterized as open item 3.1.4-1(b).

[Operating Experience] The applicant states that RV Internals Program is a new inspection, and no operating experience exists. The applicant has stated that RV internals inspections proposed for McGuire 1 will be based upon implementation of a similar program for the Oconee Unit 1, and that the decision to examine the RV internals for McGuire 2 and the Catawba reactor units will be based on the combined RV internals inspection results for Oconee Unit 1 and McGuire 1. This is acceptable to the staff since there is no current industry experience that could assist the applicant in developing the other program attributes for the RV Internal Inspection.

FSAR Supplement: The staff reviewed Appendix A - FSAR Supplement (McGuire Section 18.2.22 and Catawba Section 18.2.21) of the LRA. The staff requests that Duke provide a commitment to update the "Detection of Aging Effects" program attribute in FSAR Supplement Section 18.2.22, "Reactor Vessel Internals Inspection," to reflect the second paragraph in the applicant's response to RAI B.27-2.

In conclusion, the staff reviewed the RV Internals Inspection Program. With the exception of open item 3.1.4-1(a) and (b), the staff finds that the implementation of this AMP will provide reasonable assurance that the cracking, loss of preload, dimensional changes, and reduction in fracture toughness of RV internals will be adequately managed such that the intended function(s) of the RV internals will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.4.3 Conclusions

The staff reviewed the information included in Section 3.1.1 of the LRA, as supplemented by the April 15, 2002 response to the RAI. With the exception of open item 3.1.4-1(a) and (b), the staff concludes that the applicant has demonstrated that the aging effects associated with the RV internals will be adequately managed so that there is reasonable assurance that these components will perform their intended function(s) consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.5 Steam Generators

Each reactor unit at McGuire and Catawba has four recirculating steam generators (SGs), with one steam generator in each of the four reactor coolant loops. The original Westinghouse (W) models D2 and D3 SGs at Catawba 1, McGuire 1, and McGuire 2 had a number of internal components, including the SG tubes and the tube support plates, that experienced significant degradation during their first few years of service. As a result, Catawba 1, McGuire 1 and McGuire 2 replaced their original SGs with the enhanced model CFR-80 replacement steam generators (RSGs) manufactured by Babcock and Wilcox International (BWI) of Canada in 1996, 1997, and 1998, respectively. The Westinghouse Model D5 SGs at Catawba 2 have not been replaced since they already incorporated many of the enhanced design features of the BWR RSGs and have not experienced the types of degradation observed in Westinghouse D2 and D3 model SGs.

All steam generators at both sites are vertical shell and U-tube evaporators with integral moisture separating equipment. Reactor coolant flows through the inverted U-tubes, entering and leaving through nozzles equipped with stainless steel safe ends located in the hemispherical bottom head of the steam generator. Steam is generated on the shell side of the tubes and the water-steam mixture flows upward through the tube bundle and into the steam drum section. Centrifugal moisture separators, located above the tube bundle, remove most of the entrained water from the steam. Steam dryers are employed to increase the steam quality before the steam flows upward to the outlet nozzle at the top of the steam generator.

While significant hardware differences exist between the Westinghouse model D5 SGs at Catawba 2 and the BWI model CFR-80 RSGs at Catawba 1, McGuire 1, and McGuire 2, the basic function is essentially identical with one exception in the feedwater delivery system. The Westinghouse model D5 SGs are equipped with presenters and feedwater flow restrictor with main feedwater delivered just above the tubesheets. Feedwater in the BWI RSGs flows directly into a down comer section distributed by a feeding header and is mixed with saturated recirculation flow before entering the boiler section. The moisture separators recirculated flow through the annulus formed by the shell and tube bundle wrapper.

3.1.5.1 Technical Information in the Application

The applicant described its AMR of the steam generators for license renewal in Section 3.1.1 of the LRA, "Aging Management Review Results Tables," as supplemented by the April 15, 2002, response to the RAI. The staff reviewed this section of the LRA to determine whether the applicant had demonstrated that the effects of aging on the steam generators will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In accordance with the Catawba and McGuire UFSARs, the steam generators are designed and fabricated in accordance with Section III of the ASME Boiler and Pressure Vessel Code requirements. The SG tubes and plugs are made from corrosion resistant thermally treated Inconel 690 for the BWI SGs and Inconel 600 for the W SGs. The channel head divider plate is nickel based alloy. The material used for the steam generator shell is made from low-alloy steel. The interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. The primary nozzles for the BWI SGs are buttered with nickel based alloy weld material. The primary side of the tubesheets is weld clad with Inconel. The tubes are hydraulically expanded for the full depth of the tubesheets after the ends are seal welded to the tubesheets cladding. Primary nozzles have stainless steel safe ends. The primary manway is made of low alloy steel clad with stainless steel (W) and nickel based alloy (BWI). The secondary side components including the steam drum, manways and their covers, handheld covers, handheld pad, and minor nozzle bosses are all made from low-alloy steel. All steam generators also have stainless steel flow restrictor.

The SG components on the primary side are exposed to borated reactor water, while on the secondary side treated water is maintained to minimize corrosion and fouling of the SG heat transfer surfaces. The design temperatures for all SGs are 343.3 °C (650 °F) on the reactor coolant side, and 315.6 °C (600 °F) on the steam side. The design pressure on the reactor coolant side is 17.13MPa (2485 psig), and 8.17 MPa (1185 psig) on the steam side. As stated in Section 3.2 of the Catawba UFSAR, the ASME classification for the secondary side is specified ASME Class 2. However, as stated in Section 5.4.2.3 of the Catawba UFSAR, the current philosophy is to design all pressure retaining parts of the SG, including both the primary and secondary pressure boundaries, to satisfy the criteria specified in Section III of the ASME Code for Class 1 components. This is applicable to RSGs where the analysis set includes not only transients associated with the Class 1 portion of these SGs, but also the transients applicable to certain non-Class 1 portions of these SGs.

3.1.5.1.1 Aging Effects

In LRA Table 3.1-1, the applicant, in accordance with 10 CFR 54.4(a), has identified that maintaining the structural integrity of the reactor pressure boundary is the applicable intended function for most steam generator components. The flow restrictor has an additional thermal-hydraulic intended function involving the provision of throttling such that the appropriate fluid flow and pressure are supplied by the system.

The aging effects associated with the SG components that require aging management are also listed in Table 3.1-1 of the LRA and include:

- loss of material in both borated and treated water for carbon steel, low-alloy steel, stainless steel, and nickel-based alloys
- cracking in carbon steel, low-alloy steel, stainless steel (including cladding materials), nickel alloy steels (including buttering material)
- loss of preload in low-alloy steel bolting

3.1.5.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, Duke identifies the AMPs for managing aging effects associated with the SG components. The aging effects for the SG components are given as cracking, loss of material, and loss of preload. In this table, the applicant lists the applicable AMPs and activities for managing these aging effects associated with the SG components and they are given as:

- chemistry control program
- fluid leak management program
- ISI plan
- Alloy 600 aging management review
- flow accelerated corrosion program
- steam generator surveillance program

The applicant concluded that these AMPs will manage the effects of aging such that the intended function of the SG components will be maintained consistent with the CLB under all design loading conditions throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

The applicant did not specifically identify any TLAA in Section 3.1.1 of the LRA that is applicable to SG components. However, Section 4.0 of the LRA identifies a TLAA for metal fatigue of ASME Class 1 and Class 2 components that applies to SG components.

3.1.5.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.1 (including Table 3.1-1) of the LRA and pertinent sections of Appendices A and B to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended function(s) of the SG components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

Table 3.1-1 of the LRA lists the SG components that are within the scope of the license renewal and identifies the aging effects that require management. The list of components within the scope of license renewal are grouped in accordance with their component types.

3.1.5.2.1 Aging Effects

In accordance with Section 3.1 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the SG components to provide reasonable assurance that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for Catawba and McGuire. This also included the plant-specific operating experience at both subject plants.

The three aging effects for the steam generator given in Table 3.1-1 of the LRA include:

- loss of material
- cracking
- loss of preload

In accordance with Section 5.4.2.1.3 of the Catawba UFSAR, additional measures are incorporated in the Westinghouse model D5 design to prevent areas of dry out in the SG and accumulation of sludge in low velocity areas. Modifications to the wrapper have increased water velocities across the TUBESHEETs. A flow distribution baffle is provided which forces the low flow area to the center of the bundle. Increased capacity blowdown pipes have been added to enable continuous blowdown of the SGs at a high volume. Stainless steel tube support plates with broached tube holes minimize tube denting and support plate erosion/corrosion.

Similar design improvements in the RSGs by BWI address a number of SG internals degradation. Tube to tubesheets crevice I.A. is avoided by selection and control of the tube alloy and development and implementation of the tube expansion tooling and procedures which minimize the crevice at the tubesheets secondary face. Tube to tubesheets crevice and primary side stress corrosion cracking is avoided by using tube expansion techniques which minimizes residual stresses. The accumulation of crud at the top of the tubesheets (tubesheet sludge piles) may be minimized through achievement of a high circulation ratio, creating high volume cross flow, high capacity blowdown capability, water chemistry limits, and provision of multiple access ports for sludge lancing. Use of “open-flow” lattice grids and stainless steel in the tube support designs limits corrosion product accumulation at tube supports and reduces denting at tube support locations. Tube vibration fretting wear at lattice grid and U-bend supports is avoided by maintaining optimum tube-to-support contact/clearance, installing U-bend supports, and selecting tube support material that resists wear when in direct contact with Inconel 690 interfaces. U-bend cracking of inner row tubes is avoided by using large minimum radius bends and stress relieving in the tightest bends.

Loss of material due to erosion and corrosion is considered significant for SG components in the secondary side which are fabricated from either carbon steel or low alloy steel. The primary manway bolted connection is susceptible to boric-acid corrosion when exposed to reactor water leaks. Industry experience also has shown that loss of material can occur in nickel-based alloy SG tubes as a result of pitting/crevice corrosion. Vibration of the SG components may result in loss of material as a result of wear. In Table 3.1-1 of the LRA, the applicant has identified loss of material as an applicable aging effect for all SG components. The staff finds this acceptable because the applicant has conservatively accounted for loss of material in the SG components that could be induced by either flow-assisted corrosion, boric acid corrosion pitting or crevice corrosion, or wear.

Cracking of SG components due stress corrosion cracking (SCC), primary water stress corrosion cracking (PWSCC), intergranular stress corrosion cracking (IGSCC), or outside diameter stress corrosion cracking (ODSCC) is an applicable aging effect. SCC results from the synergistic effects of tensile stresses and a corrosive environment on a susceptible material. SCC is a particular concern for the SG tubes, tube support plates, given the potential for occluded environmental conditions in crevice areas. Welds in the nozzles and their safe ends are also vulnerable to cracking. In Table 3.1-1 of the LRA, the applicant has identified cracking as an applicable aging effect for most SG components. The staff finds this acceptable because the applicant has conservatively accounted for cracking in the SG components that are susceptible to cracking by SCC, PWSCC, IGSCC, or ODSCC. Cracking of SG components by thermal fatigue is addressed in Section 4.3 of the application. The staff's evaluation of cracking of SG components by thermal fatigue is documented in Section 4.3 of this SER.

Stress relaxation in the bolted connections under long-term exposure to high constant strain and elevated temperature may lead to loss of preload. The manway bolts and handhole bolts are susceptible to this aging effect. In Table 3.1-1 of the LRA, the applicant has identified loss of preload as an applicable aging effect for the SG bolting. The staff finds this acceptable because the applicant has conservatively accounted for potential losses of preload in SG bolted connections that could result from stress relaxation.

Catawba 1 completed its first fuel cycle of operation with the replacement SGs (BWR RSGs) in November 1997. Based on industry guidelines for inspection programs for steam generator internals, as described in NUREG/CR-6754, "Review of Industry Responses to NRC Generic Letter 97-06 on Degradation of Steam Generator Internals," the Catawba 1 SG tubing was inspected using eddy current testing, and the upper-bundle and tubesheet regions were inspected either visually or by remote video camera. Similar inspections were also completed on the BWI RSGs at Millstone 2 and Ginna. During SG internal inspections in these three plants after their first service period, it was determined that positioning of the U-bend support components could result in contact between peripheral tubes. The routine ongoing outage cycle inspections (by eddy current test and/or secondary side visual) will monitor the condition over time. No other evidence of degradation in the steam drum, upper bundle (U-bend) and tubesheet regions was observed during these inspections. The applicant has recognized this particular degradation both in addressing the design improvements associated with BWI RSGs and in the operating experience for the steam generator surveillance program in Section B.3.31 of the LRA.

In its April 15, 2002, response to RAI 2.3.1-4, which pertained to staff's scoping and screening evaluation that is documented in Section 2.3.1.6 of this SER, the applicant added the SG tube supports to the scope of license renewal. The applicant identified that the tube supports for the SGs perform a support function to the pressure boundary function of the SG tubes and include components such as lattice grid support plates, U-bend anti-vibration bars, the shroud, lattice ring and U-bend arch bars, stay rods, tube bundle wrapper, and the tube support plates. The applicant stated that these are fabricated from either alloy steel, stainless steel, or carbon steel and are exposed to treated water conditions. The applicant stated both loss of material and cracking as applicable effects for the surfaces of tube support components that are exposed to treated water. The staff's evaluations of these materials in treated water conditions have been discussed in previous paragraphs of this Section. The staff concludes that the applicant's identification of aging effects for the tube supports is acceptable because the applicant has conservatively accounted for mechanisms that could lead to loss of material or cracking in these components, as discussed in the previous paragraphs in this Section.

On the basis of the description of the internal and external environments, materials used, and the applicant's review of industry and plant-specific experience, the staff concludes that the applicant has identified all aging effects that are applicable for the SG components.

3.1.5.2.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant specified the following AMPs as being applicable to the steam generators:

- Chemistry Control program
- Fluid Leak Management program
- ISI Plan
- Alloy 600 Aging Management Review
- Flow Accelerated Corrosion program
- Steam Generator Surveillance program

The Chemistry Control program (Section B.3.6 of Appendix B to the LRA) provides water quality that is compatible with the materials of construction used for the McGuire and Catawba SG components in order to minimize loss of material and cracking. This program is developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience.

The staff notes that, in Table 3.1-1, the Chemistry Control program is used in conjunction with the ISI plan to mitigate cracking and loss of material in some SG components. For other SG components, the Chemistry Control program is complemented by the Alloy 600 Aging Management Review, the Steam Generator Surveillance program, and the Flow Accelerated Corrosion program. The staff finds this general approach to the management of cracking and loss of material to be acceptable, since these additional programs are able to provide feedback on the effectiveness of the Chemistry Control program during the period of extended operation.

For some SG components requiring AMRs, the applicant proposed that the chemistry control program by itself would be capable of managing the effects of aging attributed to the components. In accordance with Table 3.1-1, the applicant stated that loss of material and cracking in the steam flow limiter, the feedwater thermal sleeves, the handhole diaphragm, and the auxiliary feedwater distribution system are managed by the Chemistry Control program alone. By letter dated January 28, 2002, the staff requested, in RAI 3.1.5-1, additional clarification of how this AMP will be used to manage loss of material and cracking in these SG components. In its response dated April 15, 2002, the applicant stated that the Chemistry Control program maintains the environment in the steam generators by controlling contaminants that could lead to loss of material and cracking. A review of the operating experience has not identified any failures due to inadequate chemistry control. This operating experience shows that the Chemistry Control program is effective in managing loss of material and cracking and supplemental activities are therefore not necessary.

Flow restrictors and steam flow limiters are located interior to feedwater/steam flow pipes, and as such may not be readily accessible for the performance of ISIs. By letter dated January 28, 2002, the staff requested, in RAI 3.1.5-2, the applicant to clarify whether the feedwater flow restrictors were included in all of the SG designs for the McGuire and Catawba units, and to describe the types of ISIs performed on these components. In its response to RAI 3.1.5-2, dated April 15, 2002, the applicant clarified that the feedwater limiters (or flow restrictors) are only present in the Catawba 2 steam generators and state that the chemistry control program provides aging management for the feedwater limiter. The applicant also stated that the steam flow restrictors identified in Table 3.1-1 (page 3.1-25, row 1) of the LRA as the "flow restrictors" incorrectly credits the ISI plan as an aging management program and that the chemistry control program provides aging management for the steam flow restrictors. Based on the applicant's operating experience, as described in its responses to RAIs 3.1.5-1 and 3.1.5-2, the staff concludes that the chemistry control program is effective in managing loss of material and cracking of the steam flow limiter, the feedwater thermal sleeves, the handhole diaphragm, and the auxiliary feedwater distribution system.

The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the steam generators. The staff's evaluation of the Chemistry Control program is documented in Section 3.0 of this SER.

The Fluid Leak Management program (Section B.3.15 of Appendix B to the LRA) was developed by the applicant in response to NRC Generic Letter 88-05. Inspections are performed to provide reasonable assurance that borated water leakage from the reactor coolant pressure boundary does not lead to undetected loss of material on the external surface of RC piping and associated components, and specifically for those made out of carbon steel or low alloy steel. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the steam generators. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

The ISI Plan (Section B.3.20 of Appendix B to the LRA) manages aging effects of loss of material, cracking, gross loss of preload, and gross reduction in fracture toughness. The scope of the ISI plan for Class 1 and Class 2 components complies with the requirements of ASME Section XI, Subsections IWB and IWC. The scope of these Section XI categories covers Class 1 and Class 2 SG components. Depending on the examination category, the methods of inspections may include visual, surface and/or volumetric examination of weld locations susceptible to aging degradation. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the steam generators. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

The Alloy 600 aging management review, as described in Appendix B, Section B.3.1 of the LRA, ensures that cracking due to PWSCC for nickel-based alloy components is adequately managed and inspected by the ISI Plan and the Steam Generator Integrity Program. This program utilizes industry and Duke operating experience to define the additional inspection work that needs to be carried out in support of the AMPs identified above. The inspection methods and frequency of inspection for the Alloy 600/690, 82/182, and 52/152 locations for the period of extended operation will be adjusted as needed, based on the review. The staff has evaluated this AMP and found it to be acceptable for managing the aging effects identified for the steam generators. The staff's evaluation of this AMP is documented in Section 3.1.2.2.2 of this SER.

In LRA Table 3.1-1, the applicant has included the SG bolting as one of the SG components requiring aging management. Loss of preload for the manway and handhole cover bolts/studs is covered by the SG bolting group. Table 3.1-1 of the LRA identified that three aging effects, including cracking, loss of material, and loss of preload, will be managed using the ISI plan and the fluid leak management program. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for steam generators. The staff's evaluation of these programs is documented in Sections 3.0.3.9.1 and 3.0.3.6 of this SER, respectively.

The flow-accelerated corrosion program, as described in Appendix B, Section B.3.14 of the LRA, is designed to manage loss of material from the carbon steel components due to flow-accelerated corrosion (FAC). The applicant states that inspection methods include volumetric examinations using ultrasonic testing and radiography to measure component wall thickness, and visual inspections when access to interior surfaces is possible. The applicant states that this AMP is consistent with the basic guidelines of EPRI Report NSAC-202L, "Recommendations for an Effective Flow Accelerated Corrosion Program." The feedwater, auxiliary feedwater and steam outlet nozzles are susceptible to FAC. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for steam generators. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

The Steam Generator Surveillance program, as described in Appendix B.3.31 of the LRA is designed to manage the loss of material and cracking of Alloy 600 and 690 steam generator tubes, including plugs and sleeves and internal support structures. The applicant stated that this program is based upon Technical Specification requirements, NEI 97-06, and the EPRI PWR Steam Generator Examination Guidelines. The inspections of the tubes and rolled plugs is by eddy current, and those plugs not accessible for eddy current examinations are visually inspected. Table 3.1-1 indicated that only the tubes and tube plugs are identified as applicable to this AMP.

In RAI 2.3.1-4, which pertained to staff's scoping and screening evaluation that is documented in Section 2.3.1.6.2 of this SER, the staff asked whether it was appropriate to exclude the SG tube support components for McGuire and Catawba from the scope of license renewal. In its April 15, 2002, response to RAI 2.3.1-4, the applicant stated that the SG tube supports are within scope of license renewal and were subject to AMRs. In its response, the applicant identified that the tube support structures include items such as lattice grid support plates, U-bend anti-vibration bars, the shroud, lattice ring and U-bend arch bars for the replacement steam generators used in the McGuire 1 and 2 and Catawba 1 SG designs, and anti-vibration bars, stay rods, tube bundle wrapper, and tube support plates for the Catawba 2 SG designs. The AMR results table for these components, which was provided in the applicant's response to RAI 2.3.1-4, identifies these components as "Tube Supports" and listed cracking and loss of material as applicable effects for these components. The applicant has credited the chemistry control program (specifically for treated water) and the steam generator surveillance program to manage loss of material and cracking in the SG tube support components. The staff has evaluated the chemistry control program as a common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of the chemistry control program is documented in Section 3.0 of this SER. The staff's evaluation of the Steam Generator Surveillance Program follows:

Steam Generator Surveillance Program

The applicant describes its Steam Generator Surveillance Program in Appendix B, Section B.3.31 of the LRA. This section of the LRA describes the applicant's evaluation of this program in terms of aging management program attributes provided in the Standard Review Plan for license renewal. The applicant credits this program as managing the effects of aging for the steam generators at all four units.

The staff reviewed the applicant's description of the program to determine whether the applicant had demonstrated that it will adequately manage the applicable effects of aging in selected steam generator components during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The Steam Generator Surveillance Program provides a comprehensive examination of the steam generator tubes and tube supports to ensure that degradation is identified, and corrective actions are taken prior to exceeding allowable limits. This program is a condition monitoring program that is credited for managing loss of material and cracking of Alloy 600 and 690 steam generator tubes and carbon steel and/or stainless steel tube supports.

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Appendix B, Section B.3.31 of the LRA, regarding the applicant's demonstration of the Steam Generator Surveillance Program to ensure that the aging effects of loss of material and cracking will be adequately managed so that intended functions will be maintained consistent with the CLB for the period of extended operation.

The applicant credited the McGuire/Catawba Steam Generator Surveillance Program for managing aging effects in the McGuire/Catawba SG components. The staff evaluated the Steam Generator Surveillance Program on the following seven program attributes for the program:

1. Scope of Program
2. Preventative Actions
3. Parameters Monitored or Inspected
4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria
7. Operating Experience

The staff's evaluations of these program attributes are documented in the paragraphs that follow. The staff's evaluation of the other three program attributes (confirmatory actions, corrective actions, and administrative controls) for the Steam Generator Surveillance Program is documented in Section 3.0.4 of this SER.

[Scope] The scope of the steam generator surveillance program includes all steam generator tubes (including plugs and sleeves) in each steam generator, and internal support structures. The staff issued an RAI to clarify whether the applicant is referring to internal support structures that are directly associated with the tubes themselves, or whether the program is designed to monitor the supports for other steam generator internal components. In its response to RAI 2.3.1-4, the applicant stated that tube support structures on the secondary side of the steam generators are subject to aging management review. The tube support structures include items such as lattice grid support plates, U-bend anti-vibration bars, the shroud, lattice ring and U-bend arch bars for the replacement steam generators (McGuire 1 and 2 and Catawba 1). For Catawba 2 items such as anti-vibration bars, stay rods, tube bundle wrapper, and tube support plates are included. These items are included as “tube supports” and the aging management review results are presented in the applicant’s response to this concern. On the basis of this evaluation, the applicant in its response stated that Table 3.1.1 of the LRA is supplemented with additional information. The SG tube support components are made out of carbon steel, low alloy steel, and stainless steel. They are susceptible to cracking and loss of material aging effects. In order to maintain the support function of these SG components, the applicant has credited this program. The staff considers the scope of Duke’s inspection program acceptable because, as discussed below, it meets both Duke’s TS and current industry guidelines, and is adequate to detect degradation of steam generator tubes and internal structures that can affect tube integrity.

[Preventive Actions] The applicant stated that no preventive actions are taken as part of this inspection program to prevent aging effects or to mitigate aging degradation, and the staff did not identify a need for any.

[Parameters Monitored or Inspected] The application stated that the AMP monitors steam generator tube wall degradation and support plate locations. The applicant also stated that the recommendations for steam generator inspections given in NEI 97-06, “Steam Generator Program Guidelines”, and the EPRI PWR Steam Generator Examination Guidelines will be followed as part of this AMP. These guidelines provide, among other things, criteria for the qualification of personnel, specific techniques, and the associated acquisition and analysis of data (including the procedure, probe selection, analysis protocol, and reporting criteria). Following the EPRI guidelines, Duke performs the appropriate type of eddy current test techniques depending on the region of the steam generator (e.g., top of the tubesheet, freespan). Inspection of tubes and plugs is carried out using eddy current examination. Tube plugs that cannot be examined in this way are examined visually. In addition to eddy current testing of SG tubes for tube wall degradation and support plate locations, visual inspections of SG internal components, loose parts monitoring, sludge pile location monitoring, and inspection of welds are performed to monitor the overall condition of the steam generator. The staff considers the parameters monitored (e.g., eddy current test and visual inspection results) acceptable because industry operating experience has demonstrated that the data obtained from these nondestructive examinations provide reasonable assurance that the effects of aging on steam generator tubes and plugs will be detected.

[Detection of Aging Effects] The applicant referred to information in the “Monitoring and Trending” section of the AMP for a description of the procedures for detecting aging effects. Aging effects are detected through inspection of the steam generators following the Improved Technical Specification (ITS) requirements and recommendations of the NEI 97-06, “Steam Generator Program Guidelines,” and EPRI PWR Steam Generator Examination Guidelines. The staff finds this overall approach for the detection of aging effects to be acceptable because the steam generator tube inspection is based on inspection methods, as specified in the ITS, NEI 97-06, and the EPRI PWR Steam Generator Examination Guidelines, that will be capable of detecting the aging effects identified by the applicant as being applicable to the SG components within scope of the Steam Generator Surveillance Program.

[Monitoring and Trending] The applicant monitors degradation from cycle to cycle as part of its commitment to NEI 97-06. The condition monitoring program applied at these units uses inspection results to ensure that steam generator tube integrity has been maintained over the past operating cycle. The applicant also considers the inspection results in its operational assessment for the upcoming cycle to ensure that the tubes will perform their intended function and remain within the licensing basis requirements. The staff considers this acceptable since the program ensures that licensing basis requirements are maintained.

[Acceptance Criteria] Acceptance criteria for the steam generator surveillance program are included in Technical Specification 5.5.9.4. In addition, data are evaluated to determine that all structural and leakage criteria were met during the past operating cycle and a projection is made by an operational assessment to determine that all tubes left in service will continue to meet licensing basis requirements until the next examination. The staff finds these acceptance criteria to be acceptable because they are based on licensing basis requirements and technical specification requirements.

[Operating Experience] The applicant stated that the McGuire 1 and 2 steam generators were replaced in 1997 and 1998, respectively. The applicant stated that the only degradation that has been identified in the replacement steam generators for these two units is caused by wear at the secondary side U-bend fan bar and lattice grid supports.

After the Catawba 1 SG replacement in 1996, wear at the secondary side U-bend fan bar supports was also detected. The Catawba 2 steam generators have not been replaced. Wear was detected in the Catawba 2 steam generators at the edge of anti-vibration bars and in the preheater section. Tube wear occurs because of interaction between the secondary side of the tubes with steam generator tube support structures. The applicant stated that the operating experience at Catawba has revealed that wear on the secondary side is very slow and readily detectable by eddy current before it is severe enough to affect tube structural integrity. The staff finds Duke's operating experience to date and the inspection program (which is based on consistent with standards, recommendations, and requirements used throughout the industry) supports the applicant's conclusion that the steam generator surveillance program is effective.

FSAR Supplement: 10 CFR 54.21(d) requires that the FSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation. For a description of the applicant's steam generator surveillance program, the applicant provided a reference to ITS 5.5.9 in Table 18-1 of Appendices A.1 and A.2 for McGuire and Catawba, respectively. The staff found that the ITS provides a description of some of the Steam Generator Surveillance Program elements, however it does not mention the inspection recommendations provided in NEI 97-06. LRA Section B.3.31 states that, in addition to the technical specification requirements, steam generator tube inspection follows the recommendations of the NEI 97-06 and EPRI PWR Steam Generator Examination Guidelines. ITS 5.5.9 does not reference NEI 97-06 or the EPRI guidelines. The staff has not approved NEI 97-06 or the EPRI guidelines; however, the staff recognizes that these two industry documents provide guidance in the development of a steam generator management program, including steam generator inspection program specifications. The steam generator management program augments the requirements of ITS 5.5.9. Therefore, the staff requests the applicant to include a reference to NEI 97-06 in a summary description of the AMP or in

Tables 18-1 of the McGuire and Catawba FSAR Supplements. This issue is characterized as open item 3.1.5-1.

On the basis of the review of the steam generator surveillance program, the staff finds that the implementation of this program will provide reasonable assurance that cracking and loss of material of steam generator tubes and tube supports will be adequately managed such that the intended function(s) of the steam generators will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.5.3 Conclusions

The staff reviewed the information included in Section 3.1.1 of the LRA, as supplemented by the April 15, 2002 response to the RAI. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the SG components will be adequately managed so that there is reasonable assurance that these components will perform their intended function(s) consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.6 Aging Management Review of Class 1 Closure Bolting

Although the LRA provided AMR results for Class 1 bolting, it did not address bolting for Non-Class 1 components. By letter dated January 23, 2002, the staff requested, in RAI 3.2-1, additional information that pertains to tables in Sections 3.2, 3.3, and 3.4 of the LRA that list closure bolting as components subject to AMR. The staff stated that since closure bolting is exposed to air, moisture, and leaking fluid (boric acid) environments, it is subject to the aging effect of loss of material and crack initiation and growth. Tables in Sections 3.2, 3.3 and 3.4 do not address these aging effects for closure bolting in these systems. The staff requested the applicant to identify the AMR results for closure bolting, or to provide a justification for excluding closure bolting from an AMR, the results of which are documented in the referenced tables of the LRA.

3.1.6.1 Aging Effects

In its response dated April 15, 2002, the applicant stated that closure bolting used in mechanical system applications would be addressed. Closure bolting in mechanical system applications can be divided between Class 1 and non-Class 1 applications. Although the LRA addressed Class 1 bolting, the applicant described its treatment of this bolting in its response. The applicant stated that Class 1 bolting associated with the RCS is covered by specific ASME Section XI activities and is addressed in Section 3.1 of the LRA. Non-Class 1 bolted closures are considered a sub-component of the components listed in the Tables of Sections 3.2, 3.3 and 3.4 of the LRA. Closure bolting exposed to air, moisture, and leaking fluid (boric acid) environments is subject to aging as a part of the bolted closure to which it belongs. Loss of material is the aging effect requiring management during the period of extended operation for carbon and low alloy steel fastener sets of bolted closures.

3.1.6.2 Aging Management Programs

The Fluid Leak Management Program and the Inspection Program for Civil Engineering Structures and Components are credited with managing this aging effect during the period of extended operation. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects of Class 1 bolting. The staff's evaluation of theses common AMPs is documented in Section 3.0 of this SER.

3.1.6.3 Conclusions

On the basis of its review of the RAI response pertaining to Class 1 bolting, the staff finds that all applicable aging effects were identified, and the aging effects identified are appropriate for the combination of materials and environments listed. The Fluid Leak Management program and the Inspection Program for Civil Engineering Structures and considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for Class 1 closure bolting. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. The staff concludes that the applicant has demonstrated that the aging effects associated with Class 1 bolting will be adequately managed so there is reasonable assurance that these components will perform their intended functions consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.7 References for Section 3.1

American Society of Mechanical Engineers (ASME)

ASME Boiler and Pressure Vessel Code, Section III, Subsection NB, "Class 1 Components."

ASME Boiler and Pressure Vessel Code, Section III, Subsection NG, "Core Support Structures."

ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB, "Requirements for Class 1 Components of Light-Water Cooled Power Plants."

ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWC, "Requirements for Class 2 Components of Light-Water Cooled Power Plants."

ASME Boiler and Pressure Vessel Code, Section XI, Appendix G, "Fracture Toughness Criteria for Protection Against Failure."

ASME Boiler and Pressure Vessel Code, Code Case N-481, "Alternative Examination Requirements for Cast Austenitic Pump Casings, Section XI, Division 1."

Electric Power Research Institute (EPRI) and Materials Reliability Program (MRP)

EPRI Report TR-105714, Volumes 1, Revision 4, and Volume 2, Revision 4 "PWR Primary Water Chemistry Guidelines," January 1999.

EPRI Report TR-102134, Revision 5, "PWR Secondary Water Chemistry Guidelines," December 1999.

EPRI Report TR 107621, Revision 1, "Steam Generator Examination Guidelines," September 1997.

EPRI Report NSAC-202L, Revision 2, “Recommendations for an Effective Flow Accelerated Corrosion Program,” December 1998.

MRP Topical Report TP-1001491, Part 2, “PWR Materials Reliability Program Interim Alloy 600 Safety Assessment for US Power Plants (MRP-44),” May 2001.

Nuclear Energy Institute (NEI)

NEI 97-06, “Steam Generator Program Guidelines,” 1997.

U.S. Nuclear Regulatory Commission (NRC)

Correspondence

Letter dated January 23, 2002, Request for Additional Information pertaining to System Scoping and Screening Results for Engineered Safety Features of the LRA (ML020240249)

Letter dated January 28, 2002, Request for Additional Information pertaining to Reactor Coolant System Sections 2.3.1, 3.1, 4.2, 4.3, 4.7.1 and Appendix B of the LRA (ML020310255)

Letter dated January 30, 2002, Request for Additional Information pertaining to Reactor Coolant System Sections 3.1 and B.3.27 of the LRA (ML020350542)

Bulletins (BL)

BL 88-09, “Thimble Tube Thinning in Westinghouse Reactors,” July 26, 1988.

BL 2001-001, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,” August 3, 2001.

BL 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,” March 18, 2002.

BL 2002-02, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,” August 9, 2002.

Code of Federal Regulations (10 CFR)

10 CFR 50.36, “Technical Specifications.”

10 CFR 50.61, “Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events.”

10 CFR 50.90, “Application for Amendment of License or Construction Permit.”

10 CFR Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants.”

10 CFR Part 50, Appendix G, “Fracture Toughness Requirements.”

10 CFR Part 50, Appendix H, “Reactor Vessel Material Surveillance Program Requirements.”

Generic Letters (GL)

GL 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components In PWR Plants,” March 17, 1988.

GL 97-01, “Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations,” April 1, 1997.

GL 97-06, “Degradation of Steam Generator Internals,” December 30, 1997.

Information Notices (IN)

IN 87-44, “Thimble Tube Thinning in Westinghouse Reactors,” September 16, 1987.

IN 2001-05, “Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3,” April 30, 2001.

Technical Reports

NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” July 2001.

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3.2 Aging Management of Engineered Safety Features

The applicant described its AMR of the engineered safety features (ESFs) for license renewal in Sections 2.3.2, "Engineered Safety Features," and 3.2, "Aging Management of Engineered Safety Features," of its LRA. The staff has reviewed these sections of the application to determine whether the applicant has provided adequate information to demonstrate that the effects of aging on ESF systems and components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

The LRA identified eight systems that will require aging management to meet the requirements of 10 CFR 54.21(a)(3) for management of aging effects. The eight systems are: annulus ventilation, containment isolation, containment air return exchange and hydrogen skimmer, containment spray, containment valve injection water, refueling water, residual heat removal, and safety injection. The LRA included a summary of the results of the aging management review for the above listed eight systems. The results are listed in Tables 3.2-1 through 3.2-8 of the LRA. The tables provide the following information: (1) component type, (2) component function, (3) material, (4) environment, (5) aging effects requiring management, and (6) the aging management programs that manage the identified aging effects.

Section 3.2 of the LRA defined the external and internal environments applicable to the ESF systems as follows.

- Air-Gas - Compressed air is ambient air that has been filtered and compressed for use in plant equipment. Compressed air may be either dry or oiled. Compressed gases include carbon dioxide, hydrogen, nitrogen, freon, or refrigeration gases used to replace freon due to environmental concerns.

- Borated Water - Borated water is demineralized water treated with boric acid.

- Raw Water - Raw water is water from a lake, pond, or river that has been rough-filtered and possibly treated with a biocide.

- Treated water - Treated water is demineralized water that may be deareated, treated with a biocide or corrosion inhibitors, or a combination of these treatments. Treated water does not include borated water, which is evaluated separately.

- Sheltered environment - The ambient conditions within the sheltered environment may or may not be controlled. The sheltered environment atmosphere is a moist air environment. Components in systems with external surface temperatures the same or higher than ambient conditions due to normal system operation are expected to be dry.

- Reactor Building - The Reactor Building environment is moist air. Components in systems with external surface temperatures the same or higher than ambient conditions due to normal system operation are expected to be dry.

- Ventilation - Ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy.

- Yard - Yard environment is moist air environment in which equipment is exposed to heat, cold, and precipitation.

To provide reasonable assurance that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for McGuire and Catawba, Duke also performed a review of industry experience and NRC generic communications relative to the ESF SSCs. In addition, relevant McGuire and Catawba operating experience have been reviewed to provide additional confidence that the set of aging effects for the specific material-environment combinations have been identified.

3.2.1 Annulus Ventilation System

3.2.1.1 Technical Information in the Application

The McGuire annulus ventilation system is an ESF that creates and maintains a negative pressure zone in the annular space between the steel primary containment and reactor building (secondary containment) to prevent the leakage of radioisotopes through the reactor building and into the environment following a loss-of-coolant- accident (LOCA). The annulus ventilation system is also designed to maintain containment isolation integrity. The Catawba annulus ventilation system is an ESF used in conjunction with the secondary containment to limit operator and site boundary doses following a design basis accident and provides long term fission product removal capability within the annulus through holdup and filtration.

3.2.1.1.1 Aging Effects

Table 3.2-1 of the LRA identified the following components that will require aging management during the period of extended operation: air flow monitors, ductwork, filters, pipe, tubing and valve bodies. The applicant identified stainless steel, carbon steel, copper, and brass as the materials of construction for the annulus ventilation components. The applicant also indicated that the environments that these components are exposed to include an internal environment of ventilation and external environments of sheltered or reactor building. The applicant identifies only loss of material as an applicable aging effect for carbon steel, copper and brass that are exposed to an external environment.

3.2.1.1.2 Aging Management Programs

The LRA identified two aging management programs that will manage the aging effects on the annulus ventilation system during the period of extended operation. These two programs are:

- fluid leak management program
- inspection program for civil engineering structures and components.

The applicant stated that the fluid leak management program and inspection program for civil engineering structures and components will be used to manage the loss of material associated with carbon steel materials. The fluid leak management program will also be used to manage the loss of material associated with brass and copper materials. A detailed description concerning each of the programs identified above is included in Appendix B of the LRA, along with the applicant’s discussion of how identified aging effects will be effectively managed for the period of extended operation.

3.2.1.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.2 of the LRA. The purpose of the review was to ascertain whether the applicant has adequately demonstrated that the effects of aging associated with the annulus ventilation system will be adequately managed so that the intended function of the systems will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.1.2.1 Aging Effects

The LRA included a summary of the results of the aging management review for the annulus ventilation system. The results are listed in Table 3.2-1 of the LRA. The materials of construction, internal/external environment and aging effects for the annulus ventilation system are:

- stainless steel in ventilation/sheltered/reactor building environments - no aging effects
- carbon steel in ventilation environments - no aging effects
- carbon steel in sheltered/reactor building environments - loss of material
- brass, copper in ventilation/sheltered/reactor building environments - loss of material

No aging effects were identified with the AMR of air flow monitors, ductwork, filters, tubing and valve bodies made of stainless steel in ventilation, sheltered or sheltered environment. Austenitic stainless steel materials are designed to be corrosion resistant in both dry or moist air environments. Cracking and corrosion generally have not been a problem for austenitic stainless steel components in ventilated air, sheltered air or reactor building air environments. The applicant, therefore, has not identified any applicable aging effects for the surfaces of stainless steel annulus ventilation system components exposed to these types of air environments.

No aging effects were identified with the AMR of carbon steel pipe and valve bodies in a ventilated air environment. The air temperature, humidity, and component temperatures do not provide a corrosive environment that would lead to aggressive general corrosion.

Loss of material was identified with the carbon steel pipe and valve bodies in sheltered air or reactor building air environments. Loss of material of carbon steel materials by corrosion may result in moist air environments, and therefore may be an applicable aging effect for the surfaces of carbon steel that are exposed to sheltered air. In addition, borated water leaks from other plant systems may also cause loss of material of carbon steel components. The applicant will use the fluid leak management program and inspection program for civil engineering structures and components to manage the loss of material associated with carbon steel pipe and valve bodies.

Loss of material was identified with brass tubing, brass valve bodies and copper tubing in the sheltered environment. Brass and copper are corrosion resistant in both dry or moist air environments. However, borated water leaks from other plant systems may cause loss of material of brass and copper components. The applicant will use the fluid leak management program to manage the loss of material associated with brass and copper materials.

The aging effects identified in LRA Table 3.2-1 are consistent with industry experience for the combinations of materials and environments listed. On the basis of it's review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.2.1.2.2 Aging Management Programs

Table 3.2-1 of the LRA identified two aging management programs that will manage the aging effects on the annulus ventilation system during the period of extended operation. These two programs are:

- fluid leak management program
- inspection program for civil engineering structures and components.

The fluid leak management program and the inspection program for civil engineering structures and components are credited with managing the aging of several components in different structures and systems and is, therefore, considered a common aging management program. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.2-1, the staff concludes that the above identified AMPs will effectively manage the aging effects of the annulus ventilation system and that there is reasonable assurance that the intended functions of the annulus ventilation system will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.1.3 Conclusions

The staff reviewed the information in Section 3.2, "Aging Management of Engineered Safety Features," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's characterization of the aging effects associated with the annulus ventilation system is consistent with published literature and industry experience. The staff further concludes that the applicant has appropriate aging management programs to effectively manage the aging effects of the annulus ventilation system and that there is reasonable assurance that the intended functions of the system will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2 Containment Isolation System

3.2.2.1 Technical information in the application

The Containment Isolation System is an ESF that prevents the leakage of uncontrolled or unmonitored radioactive materials to the environment by closing all fluid penetrations not required for operation of the Engineered Safeguards System. The LRA identifies the following twelve subsystems of the containment isolation system:

Breathing air system: The McGuire breathing air system provides an adequate capacity of air to meet appropriate American National Standards Institute (ANSI) specifications. The breathing air system is also relied upon to provide and maintain containment isolation and closure. The Catawba breathing air system supplies clean, oil free, compressed air to various locations in the auxiliary building, monitor tank building, and containment for breathing protection against airborne contamination during the performance of certain maintenance and cleaning operations.

Containment air release and addition system: The McGuire containment air release and addition system maintains containment pressure between the McGuire Technical Specification limits of -0.3 to +0.3 psig. Increases in pressure during normal operation are controlled by venting the containment through the containment air release and addition filters. The Catawba containment air release and addition system maintains containment pressure between the Catawba Technical Specification limits of -0.1 to +0.3 psig during normal plant operation. An increase in pressure during normal operation is controlled by the containment air release fans taking suction from the containment and passing through the containment air release filters.

Containment hydrogen sample and purge system: The McGuire Nuclear Station has no system corresponding to the Catawba containment hydrogen sample and purge system. The Catawba containment hydrogen sample and purge system is used after a loss-of-coolant accident (LOCA) to monitor the hydrogen concentration inside containment, and if necessary, reduce the levels of hydrogen by manually purging the hydrogen from containment into the annulus.

Containment purge ventilation system: During periods of sustained personnel access (including refueling), the McGuire containment purge ventilation system reduces the airborne radioactivity levels in containment by purging the upper containment atmosphere to the environment via the unit vent stack. The Catawba containment purge system reduces the airborne radioactivity levels in containment by purging the upper containment, lower containment, and the incore instrumentation room atmosphere to the unit vent stack when periods of personnel access are required.

Containment ventilation cooling water system: The McGuire containment ventilation cooling water system operates in conjunction with the nuclear service water system to supply cooling water to ventilation units located in the reactor and auxiliary buildings. The Catawba Nuclear Station does not have a containment ventilation cooling water system. The comparable components cooled by the McGuire containment ventilation cooling water system are cooled by the Catawba nuclear service water system.

Conventional chemical addition system: The McGuire conventional chemical addition system uses the auxiliary feedwater supply headers to provide chemical addition to the steam generators. The Catawba Nuclear Station does not have a conventional chemical addition system. The comparable components to the McGuire conventional chemical addition system are contained in the Catawba auxiliary feedwater system.

Equipment decontamination system: The McGuire equipment decontamination system provides decontamination of station equipment before personnel use. The original design of McGuire included containment isolation capability; however, the design was modified by the installation of a sleeve cap on the annulus side of the penetration thereby removing the containment isolation function. Associated with the capped penetration are remaining components, including piping. The applicant determined that these components have no component intended function. Therefore, no mechanical components in the equipment decontamination system are subject to aging management review. The Catawba equipment decontamination system provides cleaning and decontamination of radioactive equipment prior to handling, maintenance or shipping. The equipment decontamination system and its components are not safety related, with the exception of the portions associated with containment isolation. The equipment decontamination system is relied upon to maintain two trains of containment isolation and maintain containment closure for shutdown.

Ice condenser refrigeration system: The primary safety function of the McGuire and Catawba ice condenser refrigeration systems is to rapidly reduce the containment pressure and temperature following any LOCA and maintain them at acceptable levels, consistent with the operation of other associated systems. The safety-related function of the mechanical systems portion of the ice condenser refrigeration system is containment isolation.

Makeup demineralized water system: The McGuire and Catawba makeup demineralized water systems provide treated and demineralized water to various plant systems and components.

Station air system: The McGuire station air system provides an adequate capacity for general station service air requirements. Normally, the instrument air system provides the station air requirements through system cross-connect valves. However, if needed, one station air system compressor is provided to furnish the station air requirements if the instrument air system is not available or desired. The station air system is also relied upon to provide and maintain containment isolation and closure. The Catawba station air system supplies low pressure compressed air for air operated tools, miscellaneous equipment, and various maintenance purposes. The station air system, if required, is available to act as a backup supply of compressed air for the instrument air system. The station air system is relied upon to provide and maintain containment isolation and closure.

Steam generator blowdown recycle system: The McGuire and Catawba steam generator blowdown recycle systems are used in conjunction with the condensate system to maintain acceptable secondary side water chemistry and control corrosion product buildup. The steam generator blowdown recycle system is designed to maintain containment isolation integrity. The system automatically isolates the blowdown lines penetrating the containment following receipt of a containment isolation signal and also following a start signal of the auxiliary feedwater system.

Steam generator wet lay-up recirculation system: The McGuire and Catawba steam generator wet lay-up recirculation systems maintain containment isolation integrity. This system contains piping and components that are used during containment isolation.

3.2.2.1.1 Aging Effects

Table 3.2-2 of the LRA identifies the following components of the containment isolation system that will require aging management: piping, tubing, orifices, annubars, and valve bodies. The applicant identified stainless steel, carbon steel, copper, brass and transite, a non-metallic cement-asbestos material, as the materials of construction for the containment isolation components. The applicant identified the reactor building and sheltered environment as the external environments, and raw water, treated water, and borated water as the internal environments. Loss of material was identified as an applicable aging effect for carbon steel, copper and brass materials. Loss of material and cracking were identified as an applicable aging effect for stainless steel materials.

3.2.2.1.2 Aging Management Programs

The LRA identified the following six aging management programs that will manage the aging effects on the containment isolation system during the period of extended operation:

- fluid leak management program
- inspection program for civil engineering structures and components
- service water piping corrosion program
- galvanic susceptibility inspection
- chemistry control program
- flow accelerated corrosion program.

Appendix B to the LRA contains a detailed description of the six previously discussed aging management programs. The LRA cites these programs as methods to manage aging effects of the containment isolation system components in the applicable environments.

3.2.2.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed Section 3.2 of the LRA. The purpose of the review was to determine whether the applicant will adequately manage the aging effects of the containment isolation system while maintaining the current licensing basis of the system's intended function.

3.2.2.2.1 Aging Effects

The LRA includes a summary of the results of the aging management review for the containment isolation system. The results are listed in Table 3.2-2 of the LRA. The materials of construction, internal/external environments and aging effects for the containment isolation system are:

- stainless steel in air-gas/sheltered/reactor building/ventilation environment - no aging effects
- embedded transite, carbon and stainless steel - no aging effects
- carbon steel in ventilation environment - no aging effects
- carbon steel in sheltered//reactor building environment - loss of material
- brass and copper materials in ventilation environment/reactor building - loss of material
- carbon steel in raw water environment - loss of materials
- stainless steel in raw water environment - loss of material
- stainless steel in treated water environment - loss of material and cracking
- carbon steel in treated water environment - loss of material
- stainless steel in borated water environment - loss of material and cracking

No aging effects were identified with the AMR of piping, tubing, orifices, annubars and valve bodies made of stainless steel in air-gas, sheltered, reactor building or ventilation environment. Austenitic stainless steel materials are designed to be corrosion resistant in dry or moist air environments. Cracking and corrosion, therefore, generally have not been a problem for austenitic stainless steel components in these environments. The applicant, therefore, did not identify any applicable aging effects for the surfaces of stainless steel components exposed to the above identified environments.

Embedded pipe made of transite, carbon or stainless steel is not susceptible to aging effects; therefore, the applicant did not identify any aging effects for the surfaces of embedded pipe.

No aging effects were identified with the AMR of carbon steel pipe and valve bodies in a ventilated air environment. The air temperature, humidity, and component temperatures do not provide a corrosive environment that would lead to aggressive general corrosion.

The applicant identified loss of material as an aging effect on carbon steel pipe and valve bodies in ventilation, sheltered or reactor building environment. Loss of material of carbon steel materials by corrosion may occur in moist air environments, and therefore may be an applicable aging effect. In addition, borated water leaks from other plant systems may also cause loss of material of carbon steel components. The applicant will use the fluid leak management program and inspection program for civil engineering structures and components to manage the loss of material associated with carbon steel pipe and valve bodies.

The applicant identified loss of material as an aging effect on brass valve bodies, brass tubing and copper tubing in the reactor building environment. Brass and copper are corrosion resistant in both dry or moist air environments. However, borated water leaks from other plant systems may cause loss of material of brass and copper components. The applicant will use the fluid leak management program to manage the loss of material associated with brass and copper materials.

The applicant identified loss of material as an aging effect on carbon steel pipe and valve bodies in the raw water environment. Loss of material from general corrosion, microbiologically induced corrosion (MIC), galvanic corrosion and pitting corrosion can occur when carbon steel materials are in contact with raw water. The applicant will use the galvanic susceptibility inspection and service water inspection program to manage the loss of material associated with carbon steel pipe and valve bodies.

The applicant identified loss of material as an aging effect on stainless steel orifices, annubars, tubing and valve bodies in the raw water environment. Loss of material from galvanic, MIC and pitting corrosion can occur when stainless steel materials with are in contact with raw water. The applicant will use the service water inspection program to manage the loss of material associated with stainless steel orifices, annubars, tubing and valve bodies.

The applicant identified loss of material and cracking as aging effects on stainless steel tubing, pipe and valve bodies in the treated water environment. Loss of material and cracking of stainless steel in treated water environment is a possible aging effect under certain conditions. Industry experience indicates that the presence of halogens in excess of 150 ppb and oxygen in excess of 100pbb in stagnant or low flow conditions could lead to loss of material from and cracking of stainless steel in treated water. Therefore, the applicant will use the chemistry control program to manage the loss of material and cracking in this environment.

The applicant identified loss of material and cracking as aging effects on stainless steel in the borated water environment. Loss of material and cracking of stainless steel in this environment is a possible aging effect under certain conditions. Industry experience indicates that the presence of halogens in excess of 150ppb, oxygen in excess of 100pbb and temperature in excess of 200^0F in stagnant or low flow conditions can lead to loss of material and cracking. Therefore, the applicant will use the chemistry control program to manage the loss of material and cracking in the borated water environment.

The aging effects identified in LRA Table 3.2-2 are consistent with industry experience for the combinations of materials and environments listed. On the basis of it's review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.2.2.2.2 Aging Management Programs

In Table 3.2-2 of the LRA, the applicant identified the following programs that will manage the aging effects associated with the containment isolation system:

- fluid leak management program
- inspection program for civil engineering structures and components
- service water piping corrosion program
- galvanic susceptibility inspection
- chemistry control program
- flow accelerated corrosion program.

The fluid leak management program, inspection program for civil engineering structures and components, service water piping corrosion program, galvanic susceptibility inspection program, chemistry control program, and flow accelerated corrosion program are credited with managing the aging of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and, with the exception of open item 3.0.3.15.2-1 pertaining to the service water piping corrosion program, found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.2-2, the staff concludes that the above identified AMPs will effectively manage the aging effects of the containment isolation system and that there is reasonable assurance that the intended functions of the containment isolation system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3 Conclusions

The staff reviewed the information in Section 3.2, "Aging Management of Engineered Safety Features," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's characterization of the aging effects associated with the containment isolation system is consistent with published literature and industry experience. The staff further concludes that, with the exception of open item 3.0.3.15.2-1, the applicant has appropriate aging management programs to effectively manage the aging effects of the containment isolation system and that there is reasonable assurance that the intended functions of the system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.3 Containment Air Return Exchange and Hydrogen Skimmer System

3.2.3.1 Technical Information in the Application

The McGuire and Catawba containment air return exchange and hydrogen skimmer system perform the following functions: (1) maintains containment pressure less than the design pressure during any high energy line break (HELB), (2) ensures hydrogen concentration remains less than the flammability limit during a LOCA, and (3) maintains containment isolation integrity for the system piping penetrating the containment.

3.2.3.1.1 Aging Effects

Table 3.2-3 of the LRA identifies the following components that will require aging management: ductwork, expansion joints, pipe, tubing and valve bodies. The applicant identified stainless steel, carbon steel, copper, and brass as the materials of construction for the containment air return exchange and hydrogen skimmer components. Loss of material was identified as an applicable aging effect for carbon steel, copper and brass exposed to the reactor building or a sheltered external environment.

3.2.3.1.2 Aging Management Programs

The LRA identifies the following two aging management programs that will manage the aging effects on the containment air return exchange and hydrogen skimmer systems during the period of extended operation:

- fluid leak management program
- inspection program for civil engineering structures and components

The applicant indicated that the fluid leak management program and inspection program for civil engineering structures and components will be used to manage the loss of material associated with carbon steel materials. The applicant stated that the fluid leak management program will be used to manage the loss of material associated with copper and brass materials. Appendix B to the LRA contains a detailed description of those two aging management programs.

3.2.3.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed Section 3.2 of the LRA. The purpose of the review was to determine whether the applicant will adequately manage the aging effects of the containment air return exchange and hydrogen skimmer system while maintaining the current licensing basis of the system's intended function.

3.2.3.2.1 Aging Effects

The LRA includes a summary of the results of the aging management review for the containment air return and hydrogen skimmer system. The results are listed in table 3.2-3 of the LRA. The materials of construction, internal/external environment and aging effects for the containment air return exchange and hydrogen skimmer system are:

- stainless steel in air-gas/ventilation/sheltered/reactor building environment - no aging effects
- brass, copper, and carbon steel in ventilation environment - no aging effects
- brass and copper in reactor building environment - loss of material
- carbon steel in sheltered/reactor building environment - loss of material

No aging effects were identified with the AMR of ductwork, expansion joints, piping, tubing, and valve bodies made of stainless steel in air-gas, sheltered, reactor building or ventilation environment. Austenitic stainless steel materials are designed to be corrosion resistant in dry or moist air environments. Cracking and corrosion, therefore, generally have not been a problem for austenitic stainless steel components in these environments. The applicant, therefore, did not identify any applicable aging effects for the surfaces of stainless steel components exposed to the above identified environments.

The applicant identified loss of material as an aging effect on carbon steel pipe and valve bodies in sheltered or reactor building environments. Loss of material of carbon steel materials by corrosion may occur in moist air environments, and therefore may be an applicable aging effect. In addition, borated water leaks from other plant systems may also cause loss of material of carbon steel components. The applicant will use the fluid leak management program and inspection program for civil engineering structures and components to manage the loss of material associated with carbon steel pipe and valve bodies.

No aging effects were identified with the AMR of brass and copper tubing and carbon steel pipe and valve bodies in a ventilated air environment. The air temperature, humidity, and component temperatures do not provide a corrosive environment that would lead to aggressive general corrosion.

The applicant identified loss of material as an aging effect on brass and copper tubing in the reactor building environment. Brass and copper are corrosion resistant in both dry or moist air environments. However, borated water leaks from other plant systems may cause loss of material of brass and copper components. The applicant will use the fluid leak management program to manage the loss of material associated with these materials.

The aging effects identified in LRA Table 3.2-3 are consistent with industry experience for the combinations of materials and environments listed. On the basis of it’s review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.2.3.2.2   Aging Management Programs

Table 3.2-3 of the LRA credits the following two aging management programs for managing the aging effects on the containment air return exchange and hydrogen skimmer systems during the period of extended operation:

- fluid leak management program
- inspection program for civil engineering structures and components

The fluid leak management program and inspection program for civil engineering structures and components are credited with managing the aging of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.2-3, the staff concludes that the above identified AMPs will effectively manage the aging effects of the containment air return and hydrogen skimmer system and that there is reasonable assurance that the intended functions of the containment air return and hydrogen skimmer system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.3.3 Conclusions

The staff reviewed the information in Section 3.2, "Aging Management of Engineered Safety Features," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's characterization of the aging effects associated with the containment air return exchange and hydrogen skimmer system is consistent with published literature and industry experience. The staff further concludes that the applicant has appropriate aging management programs to effectively manage the aging effects of the containment air return exchange and hydrogen skimmer system and that there is reasonable assurance that the intended functions of the system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.4 Containment Spray System

3.2.4.1 Technical Information in the Application

The applicant described its AMR for the containment spray system (CSS) in Section 3.2 of the LRA. The CSS removes thermal energy from the containment atmosphere in the event of a loss-of-coolant-accident or main steam line break events. The CSS perform this function in conjunction with the emergency core cooling systems, which cool the reactors during injection and recirculation modes of emergency operations. The heat removal capabilities of the CSS maintain the containment pressures to below the design pressure values after the ice in the respective ice condensers has been depleted. The CSS also serve to remove fission product iodine from the post-accident containment atmospheres.

3.2.4.1.1 Aging Effects

Table 3.2-4 of the LRA identified the following components that are subject to AMRs: flow orifices, heat exchangers and their sub-components, piping, pump casings, spray nozzles, tubing, and valve bodies. In Table 3.2-4 of the LRA, the applicant identifies that the specific CSS components are fabricated from stainless steel materials, with the following exceptions:

- portions of the CSS heat exchanger channel heads and shells are fabricated from carbon steel

- tubing for McGuire CSS heat exchanger 2NSHX0004 is fabricated from titanium instead of stainless steel
- portions of the Catawba CSS heat exchanger tubesheets are fabricated from carbon steel

Loss of material was identified as an applicable aging effect for carbon steel materials. Loss of material and fouling were identified as applicable aging effects for titanium tubes. Loss of material and cracking were identified with stainless steel materials.

3.2.4.1.2 Aging Management Programs

The applicant credits the following programs and activities for managing the aging effects attributed for the CSS components:

- borated water systems stainless steel inspection
- chemistry control program
- fluid leak management program
- heat exchanger performance testing activities - containment spray activities
- heat exchanger preventative maintenance activities - containment spray
- inspection program for civil engineering structures and components
- service water piping corrosion program

3.2.4.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.2. (including Table 3.2-4) and pertinent sections of Appendices A and B to the LRA in order to ascertain that the effects of aging associated with CSS will be adequately managed so that the intended function(s) will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.4.2.1 Aging Effects

Table 3.2-4 of the application identifies which of these aging effects are applicable to the specific CSS components identified in the table(s) as being within the scope of license renewal. Specifically Table 3.2-4 identifies that the following aging effects are applicable to the material/environmental combinations for the CSS components:

- stainless steel components in borated water environments - loss of material and cracking
- internal surfaces of stainless steel or titanium tubes in raw water environments - loss of material and fouling
- external surface of titanium tubes in borated water environments - no aging effects identified
- other stainless steel components in raw water environments- loss of material
- stainless steel components in contact with sheltered air, ventilation air, or reactor building air environments - no aging effects identified
- carbon steel components in external sheltered air environments or internal raw water environments - loss of material

Industry experience and experimental data has demonstrated that austenitic stainless steel materials in borated water solutions may be susceptible to stress corrosion cracking or loss of material as a result of pitting or general corrosion, with elevated levels of oxidizing impurity species (i.e., oxygen, sulfates, halides, etc.) increasing the potential for these aging effects to occur. These aging effects are therefore applicable to the stainless steel CSS components in contact with borated water solutions. These aging effects are also applicable to portions of the stainless steel CSS piping (i.e., the CSS piping risers) that are exposed to alternating borated-wet and dry-air environments, as any oxidizing contaminants may concentrate in the piping sections and create an environment conducive to pitting or stress corrosion cracking. For stainless steel (or titanium) heat exchanger tubes exposed to interior raw water environments, the tubes that may be susceptible to biological-induced fouling, which if unattended to, has the potential to block the flow of coolant through the tubes and in some cases to produce corrosive environments that could lead to a loss of the tube material. The applicant has appropriately identified these aging effects (i.e., cracking, loss of material, fouling) in its analyses for the CSS stainless steel components that are exposed to borated or raw water sources, or to alternating borated-wet and dry-air environments.

Austenitic stainless steel materials are designed to be corrosion resistant in both dry or moist air environments. Cracking and corrosion therefore generally have not been a problem for austenitic stainless steel components in ventilated air, sheltered air or reactor building air environments. The applicant, therefore, has not identified any applicable aging effects for the surfaces of stainless steel CSS components exposed to these types of air environments. Based on these considerations, the staff concludes that the applicant's identification of the aging effects for stainless steel CSS components is acceptable.

The carbon steel CSS heat exchanger components are in contact with sheltered air environments on their external surfaces, and either raw water or other stainless steel heat exchanger components on their internal surfaces. Loss of material of carbon steel materials by corrosion may result in moist air environments, and therefore may be an applicable aging effect for the surfaces of carbon steel CSS heat exchanger components that are exposed to sheltered air. The surfaces of carbon steel CSS heat exchanger components that the exposed to raw water environments may be prone to loss of material as a result of general or localized corrosion, or by erosion from particulate (silt, dirt, etc.) when the raw water flow velocities are high. The carbon steel CSS heat exchanger components in contact with stainless steel heat exchanger components may be prone to loss of material by corrosion if the adjacent stainless steel heat exchanger component is subjected to an internal, corrosive borated water or raw water environment, and if the stainless steel component has cracked sufficiently to the leak the fluid onto the external surfaces of the carbon steel component. The applicant has appropriately identified loss of material as an applicable aging effect for the carbon steel CSS heat exchanger components that are exposed to these environments.

The aging effects identified in LRA Table 3.2-4 are consistent with industry experience for the combinations of materials and environments listed. On the basis of it's review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.2.4.2.2 Aging Management Programs

Table 3.2-4 of the LRA states that the following aging managements programs are credited for managing the aging effects attributed to the CSS components:

- borated water systems stainless steel inspection
- chemistry control program
- fluid leak management program
- heat exchanger performance testing activities - containment spray activities
- heat exchanger preventative maintenance activities - containment spray
- inspection program for civil engineering structures and components
- service water piping corrosion program

The applicant will use the fluid leak management program (Section B.3.15 of the LRA) and the inspection program for civil engineering structures and components (Section B.3.21 of the LRA) to manage loss of material in carbon steel CSS components exposed to sheltered air environments. The applicant will use the containment spray heat exchanger performance testing activities (Section B.3.17.2 of the LRA) and the containment spray heat exchanger preventative maintenance activities (Section B.3.17.3 of the LRA) to manage fouling and loss of material in the internal heat exchanger tube surfaces (stainless steel or titanium) that are exposed to raw water environments, respectively. The applicant will use the service water piping corrosion program (Section B.3.29 of the LRA) to manage the internal surfaces of carbon or stainless steel components exposed to raw water environments. The applicant will use the chemistry control program (Section B.3.6 of the LRA) to manage loss of material and cracking in stainless steel CSS components exposed to borated water environments. As an added precaution, the applicant will use the borated water systems stainless steel inspection program (Section B.3.4 of the LRA) as an added program for managing loss of material and cracking in the stainless steel CSS piping risers, as the risers may be subjected to periods of alternating wet borated water and dry air environments.

The borated water systems stainless steel inspection program, chemistry control program, fluid leak management program, inspection program for civil engineering structures and components, and service water piping corrosion program are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and, with the exception of open item 3.0.3.15.2-1 pertaining to the service water piping corrosion program, found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. The staff's evaluation of the heat exchanger performance testing activities - containment spray program and the heat exchanger preventive maintenance activities - containment spray program follows.

<u>Performance Testing Activities - Containment Spray Heat Exchanger</u>

The applicant described its performance testing activities of the containment spray heat exchangers in Section B.3.17.2.1 of Appendix B of the LRA. The staff reviewed the LRA to determine whether the applicant had demonstrated this program will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

The applicant stated that the purpose of performance testing activities - containment spray heat exchangers is to manage fouling of stainless steel and titanium heat exchanger tubes that are exposed to raw water. The performance testing activities - containment spray heat exchangers is a performance monitoring program that monitors specific component parameters to detect the presence of fouling, which can affect the heat transfer function of the component.

The staff's evaluation of the performance testing activities - containment spray heat exchangers program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope] The scope of the performance testing activities - containment spray heat exchangers includes the McGuire and Catawba containment spray heat exchanger tubes. The staff finds the scope to be appropriate because it includes the stainless steel and titanium heat exchanger tubes that are exposed to raw water and the potential for fouling.

[Preventive or Mitigative Actions] The applicant stated that no actions are taken as part of these programs to prevent aging effects or to mitigate aging degradation. The staff finds this acceptable and agrees with the applicant that the purpose of the performance testing activities is to detect, not prevent, tube fouling.

[Parameters Monitored or Inspected] The performance testing activities - containment spray heat exchangers involve monitoring of heat transfer capability by performance of a heat capacity test. Based on a review of the program purpose and scope, the staff finds the parameters being monitored or inspected to be acceptable because they enable the applicant to identify tube fouling before the loss of component intended function.

[Detection of Aging Effects] The applicant stated that in accordance with the information provided under monitoring and trending, performance testing activities - containment spray heat exchangers will detect fouling prior to loss of the component intended function(s). The staff agrees that the applicant is capable of identifying tube fouling prior to loss of intended function through performance testing.

[Monitoring and Trending] The applicant stated that performance testing activities - containment spray heat exchangers involve calculation of a raw water fouling factor using tube and shell side inlet and outlet temperatures and flow rates through the tubes. The applicant then uses the results of the fouling factor calculation to trend against a baseline value for indication of tube (heat transfer surface) cleanliness. The applicant stated that the procedures are performed on each of the containment spray heat exchangers annually at Catawba and every three years at McGuire. The applicant refers to information provided under operating experience as justification for the extended frequency at McGuire.

Based on the review of the monitoring and trending information provided in the application, the staff finds the monitoring and trending activities acceptable, because they allow the applicant to identify fouling or degradation in a timely manner given the type of inspections performed and the frequency.

[Acceptance Criteria] The applicant stated that the acceptance criteria of the performance testing activities - containment spray heat exchangers are established by heat removal capacity calculations. The comparison of the calculated to the measured heat removal capacity must ensure that the heat exchangers are able to perform their design basis function. The staff's review found the acceptance criteria to be acceptable because it allows the applicant to identify tube fouling and take corrective action prior to loss of component function.

[Operating Experience] The applicant stated that operating experience has demonstrated that heat capacity tests provide adequate indication to predict when corrective action is required for heat transfer surface fouling. Corrective action in the form of tube cleaning, for example, is performed before the loss of the component intended function. Because the containment spray heat exchangers are used for emergency functions only, the applicant stated that placing the heat exchangers in wet lay-up several years ago has minimized buildup of fouling materials on the tubes. The applicant stated that the wet lay-up has proven so successful at McGuire that the frequency of heat capacity testing has been extended to a three-year frequency. Experience has shown that a three-year frequency allows for timely corrective action. Corrective action in the form of tube cleaning, for example, is performed before the heat transfer function of the heat exchanger tubes is degraded below its required capacity.

Based on the review of the applicant's operating experience with the performance testing activities, the staff finds that a basis exists for the extended interval between activities at McGuire. The staff also found that the operating experience demonstrates the effectiveness of the performance testing activities - containment spray heat exchangers in identifying tube fouling before it can affect system performance.

FSAR Supplement: In Appendix A-1, Section 18.2.13 and Appendix A-2, Section 18.2.12, the applicant has provided proposed FSAR Supplements for McGuire and Catawba, respectively. The staff reviewed this information and found it to be consistent with the information provided in Appendix B, Section B.3.17 and is therefore acceptable.

The staff reviewed the information in Section B.3.17.2.1 of the LRA. On the basis of its review and the above evaluation, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the performance testing activities - containment spray heat exchangers program will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Preventive Maintenance Activities - Containment Spray Heat Exchangers

The applicant described its preventive maintenance activities of the containment spray heat exchangers in Section B.3.17.2.2 of Appendix B of the LRA. The staff reviewed the LRA to determine whether the applicant had demonstrated that this program will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

The applicant stated that the purpose of this activity is to manage loss of material for parts of the containment spray heat exchanger exposed to raw water. The heat exchanger preventive maintenance activities - containment spray is a condition monitoring program that monitors specific component parameters to detect the presence and assess the extent of material loss that can affect the pressure boundary function of the heat exchanger. The applicant credits this program with managing loss of material for stainless steel and titanium materials.

The staff's evaluation of the preventive maintenance activities for the containment spray heat exchangers program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope] The applicant defined the scope of the heat exchanger preventive maintenance activities - containment spray, to include the McGuire and Catawba containment spray heat exchanger tubes. The applicant relies on other aging management programs, such as the chemistry control program, to manage the aging effects of the heat exchanger shell, channel head, and tubesheets. The staff finds that the scope is appropriate for the described purpose, because it includes those major components in the containment spray system exposed to raw water.

[Preventive or Mitigative Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff agrees with the applicant because the purpose of the program is to detect and assess the extent of material loss, not to prevent such loss.

[Parameters Monitored or Inspected] The applicant stated that the heat exchanger preventive maintenance activities - containment spray inspects the heat exchanger tubes to provide an indication of loss of material. The staff finds the parameters monitored to be acceptable, since the parameters evaluated and the methods used are comparable to industry practice and will result in detecting material loss before loss of component function.

[Detection of Aging Effects] The applicant stated that the heat exchanger preventive maintenance activities - containment spray will be capable of detecting loss of material due to crevice, pitting and microbiologically influenced corrosion prior to loss of the component intended functions. The staff finds this acceptable because the inspections are performed periodically, the program is capable of detecting and correcting aging degradation before loss of component function.

[Monitoring and Trending] The applicant stated that the heat exchanger preventive maintenance activities - containment spray performs eddy current testing on the heat exchanger tubes to measure wall thickness in order to detect areas with loss of material. At Catawba, NDT is performed on the perimeter tubes of each containment spray heat exchanger at least every five years. The applicant's program requires analysis following each NDT to determine the need for further testing, replacement or repair. The applicant noted that the perimeter tubes comprise approximately 15 percent of the total tubes. At McGuire, NDT is performed on each heat exchanger as needed based on operating experience and engineering evaluation of test data. Based on the information provided in the application, the staff finds that because the monitoring is done at a regular frequency (Catawba) or based on operating experience and engineering judgment (McGuire), the program is capable of detecting and correcting aging degradation before loss of component function.

[Acceptance Criteria] The applicant stated that the acceptance criterion for the heat exchanger preventive maintenance activities - containment spray is no loss of material of the tubes that could result in a loss of the component intended function as determined by engineering judgment. The staff does not consider this an adequate acceptance criterion for the heat preventive maintenance activities AMP. In addressing the acceptance criteria, the staff requests the applicant to specify parameters with quantitative limits (e.g., percent of flow blockage or percent of loss of heat transfer). Because the same staff finding was identified for the heat exchanger preventive maintenance activities - pump motor air handling units, as documented in Section 3.0.3.9.1.2 of this SER, this is characterized as open item 3.0.3.9.1.2-1(c).

[Operating Experience] The applicant stated that operating experience associated with the heat exchanger preventive maintenance activities - containment spray has demonstrated that the eddy current testing (ECT) provides adequate information on the extent of wall loss present in the heat exchanger tubes to predict when corrective action is required. Corrective action in the form of tube plugging, for example, is performed by the applicant before the loss of the component intended function.

The applicant noted that some tube plugging has occurred, particularly early in service life. At Catawba, the applicant stated that the tube plugging rate has been essentially flat for the past several years due to operational improvements, including placing the heat exchangers in wet lay-up. The wet lay-up has proven so successful at McGuire that according to the applicant, most recent test results indicate negligible tube wall degradation over several years. The staff agrees that because the monitoring methods are based on proven NDT techniques, and based on operating experience, the program is reliable to identify loss of material and take corrective action before loss of component function.

FSAR Supplement: In Appendix A-1, Section 18.2.13 and A-2, Section 18.2.12, the applicant has provided proposed FSAR Supplements for McGuire and Catawba, respectively. The staff reviewed this information and found it to be consistent with the information provided in Appendix B, Section B.3.17 and is therefore acceptable.

The staff reviewed the information in Section B.3.17.2.2 of the LRA. On the basis of its review and the above evaluation, with the exception of open item 3.0.3.9.1.2-1(c) pertaining to acceptance criteria for the heat exchanger preventive maintenance activities, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the preventive maintenance activities - containment spray heat exchangers program will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on its review of Table 3.2-4 and Appendix B of the LRA, with the exception of open item 3.0.3.9.1.2-1(c) pertaining to acceptance criteria for the heat exchanger preventive maintenance activities and open item 3.0.3.15.2-1 pertaining to the service water piping corrosion program, the staff concludes that the above identified AMPs will effectively manage the aging effects of the CSS and that there is reasonable assurance that the intended functions of the CSS will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.4.3 Conclusions

The staff reviewed the information in Section 3.2, "Aging Management of Engineered Safety Features," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's characterization of the aging effects associated with the CSS is consistent with published literature and industry experience. The staff further concludes that, with the exception of open items 3.0.3.9.1.2-1(c) and 3.0.3.15.2-1, the applicant has appropriate aging management programs to effectively manage the aging effects of the CSS and that there is reasonable assurance that the intended functions of the system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.5 Containment Valve Injection Water System

3.2.5.1 Technical Information in the Application

The McGuire Nuclear Station does not have containment valve injection water system. The Catawba Nuclear Station containment valve injection water system is designed to inject water between the two seating surfaces of double disc gate valves used for containment isolation. The injection pressure is higher than containment design peak pressure during a LOCA. This will prevent leakage of the containment atmosphere through the gate valves, thereby reducing potential offsite dose below the values specified by Title 10 CFR Part 100 limits following the postulated accident.

3.2.5.1.1 Aging Effects

Table 3.2-5 of the LRA identified the following components that will require aging management during the period of extended operation: pipe, tanks, tubing and valve bodies. The material of construction for the above listed components is stainless steel. Loss of material and cracking were identified as applicable aging effects for the containment valve injection water system.

3.2.5.1.2 Aging Management Programs

The LRA identified that the treated water system stainless steel inspection aging management program will manage the aging effects on the containment valve injection water system during the period of extended operation. A detailed description of the program is included in Appendix B of the LRA, along with the applicant's discussion of how the identified aging effects will be effectively managed for the period of extended operation.

3.2.5.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.2 of the LRA. The purpose of the review was to ascertain whether the applicant has adequately demonstrated that the effects of aging on the containment valve injection water system will be adequately managed so that the intended function of the systems will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.5.2.1 Aging Effects

The LRA included a summary of the results of the aging management review for the containment valve injection water system. The results are listed in Table 3.2-5 of the LRA. The materials of construction, internal/external environment, and aging effects for the containment valve injection water system are:

- stainless steel in sheltered/ventilation/reactor building environment - no aging effects
- stainless steel in treated water environment - loss of material and cracking

Austenitic stainless steel materials are designed to be corrosion resistant in both dry or moist air environments. Cracking and corrosion therefore generally have not been a problem for austenitic stainless steel components in ventilated air, sheltered air or reactor building air environments. The applicant, therefore, has not identified any applicable aging effects for the surfaces of stainless steel containment valve injection water system components exposed to these types of air environments.

Loss of material and cracking in stainless steel were identified as aging effects in treated water environment. Loss of material and cracking of stainless steel in treated water environment is possible aging effect under certain conditions. Industry experience indicated that presence of halogens in excess of 150 ppb and oxygen in excess of 100 pbb in stagnant or low flow conditions could lead to loss of material and cracking of stainless steel in treated water environment. Therefore, the applicant will use the treated water systems stainless steel inspection program to manage the loss of material and cracking in treated water environment.

The aging effects identified in LRA Table 3.2-5 are consistent with industry experience for the combinations of materials and environments listed. On the basis of it's review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.2.5.2.2 Aging Management Programs

The applicant identified that the treated water system stainless steel inspection aging management program will be used to manage the aging effects associated with the containment valve injection water system. The treated water system stainless steel inspection aging management program is credited with managing the aging of several components in different structures and systems and is, therefore, considered a common aging management program. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.2-5, the staff concludes that the above identified AMPs will effectively manage the aging effects of the containment valve injection water system and that there is reasonable assurance that the intended functions of the containment valve injection water system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.5.3 Conclusions

The staff reviewed the information in Section 3.2, "Aging Management of Engineered Safety Features," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's characterization of the aging effects associated with the containment valve injection water system is consistent with published literature and industry experience. The staff further concludes that the applicant has appropriate aging management programs to effectively manage the aging effects of the containment valve injection water system and that there is reasonable assurance that the intended functions of the system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.6 Refueling Water System

3.2.6.1 Technical Information in the Application

The McGuire refueling water system provides a source of borated water to be used during refueling to mitigate the consequences of a FSAR Chapter 15 accident. This system also provides borated makeup water for the spent fuel pool. The system can remove impurities from the refueling cavity and transfer canal during refueling, and it can clean the refueling water storage tank water following refueling. The refueling water system provides a means of transferring the final 30 percent of the refueling water between the refueling cavity and the refueling water storage tank. It also provides a secondary means of filling the refueling cavity from the refueling water storage tank. The Catawba refueling water system provides an adequate supply of borated water to the emergency core cooling system and containment spray system in order to mitigate the consequences of a design basis event. The refueling water system, along with the safety injection system, residual heat removal system, and chemical and volume control system function together to form the emergency core cooling system.

3.2.6.1.1 Aging Effects

Table 3.2-6 of the LRA identifies the following components that will require aging management: expansion joints, refueling water storage tanks, piping, tubing and valve bodies. The applicant identified stainless and carbon steels as the materials of construction for the refueling water system components. Loss of material was identified as an applicable aging effect for carbon steel materials exposed to the following environments: ventilation, yard, and borated water. Loss of material and cracking were identified as applicable aging effects for stainless steel materials exposed to an internal environment of borated water.

3.2.6.1.2 Aging Management Programs

The LRA identifies the following four aging management programs that will manage the aging effects of the refueling water system:

- chemistry control program
- borated water systems stainless steel inspection
- inspection program for civil engineering structures and components
- preventative maintenance activities - refueling water storage tank internal coating inspection

Appendix B of the LRA contains a detailed description of those four aging management programs. The LRA cites these programs as methods to manage aging effects of the refueling water system components in applicable environments

3.2.6.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed Section 3.2 of the LRA. The purpose of the review was to determine whether the applicant will adequately manage the aging effects of the refueling water system while maintaining the current licensing basis of the system's intended function.

3.2.6.2.1 Aging Effects

The LRA includes a summary of the results of the aging management review for the refueling water system. The results are listed in table 3.2-6 of the LRA. The following list summarizes the materials of construction, the internal/external environments and aging effects for the refueling water system:

- stainless steel in yard/ventilation/sheltered/reactor building environments - no aging effects
- stainless steel in borated water environment - loss of material and cracking
- carbon steel in ventilation environment - no aging effects
- carbon steel in yard environments - loss of material
- carbon steel in borated water environment - loss of material

No aging effects were identified with the AMR of piping, tubing, the refueling water storage tank and valve bodies made of stainless steel in yard, sheltered, reactor building or ventilation environments. Austenitic stainless steel materials are designed to be corrosion resistant in dry or moist air environments. Cracking and corrosion, therefore, generally have not been a problem for austenitic stainless steel components in these environments. The applicant, therefore, did not identify any applicable aging effects for the surfaces of stainless steel components exposed to the above identified environments.

The applicant identified loss of material and cracking as aging effects on stainless steel in the borated water environment. Loss of material and cracking of stainless steel in this environment is a possible aging effect under certain conditions. Industry experience indicates that the presence of halogens in excess of 150 ppb, oxygen in excess of 100 pbb and temperature in excess of 200 °F in stagnant or low flow conditions can lead to loss of material and cracking. Therefore, the applicant will use the chemistry control program and the borated water systems stainless steel inspection program to manage the loss of material and cracking in the borated water environment.

No aging effects were identified with the AMR of carbon steel pipe and valve bodies in a ventilated air environment. The air temperature, humidity, and component temperatures do not provide a corrosive environment that would lead to aggressive general corrosion.

The applicant identified loss of material as an aging effect on the carbon steel refueling water storage tank in a yard environment. Loss of material of carbon steel materials by corrosion may occur in moist air environments, and therefore may be an applicable aging effect. In addition, borated water leaks from other plant systems may also cause loss of material of carbon steel components. The applicant will use preventative maintenance activities such as the refueling water storage tank internal coating inspection and the inspection program for civil engineering structures and components to manage the loss of material associated with the carbon steel refueling water storage tank.

The applicant identified loss of material as an aging effect on the carbon steel refueling water storage tank in the borated water environment. Loss of material of carbon steel materials by boric acid corrosion may occur in borated water environments, and therefore may be an applicable aging effect. The applicant will use preventative maintenance activities such as the refueling water storage tank internal coating inspection to manage the loss of material associated with the carbon steel refueling water storage tank.

The aging effects identified in LRA Table 3.2-6 are consistent with industry experience for the combinations of materials and environments listed. On the basis of it's review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.2.6.2.2 Aging Management Programs

The applicant identified the following four aging management programs that will manage the aging effects of the refueling water system:

- chemistry control program
- borated water systems stainless steel inspection program
- inspection program for civil engineering structures and components
- preventive maintenance activities - refueling water storage tank internal coating inspection program

The chemistry control program, borated water systems stainless steel inspection program, inspection program for civil engineering structures and components, preventive maintenance activities - refueling water storage tank internal coating inspection program are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. The staff's evaluation of the preventive maintenance activities - refueling water storage tank internal coating inspection program follows:

<u>Preventative Maintenance Activities - Refueling Water Storage Tank Internal Coating Inspection</u>

The applicant developed the preventative maintenance activities - refueling water storage tank internal coating inspection program to manage the potential aging of the carbon steel refueling water storage tanks at McGuire. The internal surfaces of the carbon steel tanks are coated with a phenolic epoxy coating to prevent borated water and air from contacting the internal surfaces. This program manages loss of material of the tanks by managing the condition of the internal coating. This program is only applicable to McGuire.

In Section B.3.24, the applicant described the preventative maintenance activities - refueling water storage tank internal coating inspection program. The purpose of the program is to manage loss of material of the internal surfaces of the carbon steel refueling water storage tanks. The internal carbon steel surfaces of the refueling water storage tank are coated with a phenolic epoxy paint that prevents borated water and air from contacting the internal surfaces. Continued presence of an intact coating precludes loss of material that could lead to loss of pressure boundary function. This preventive maintenance activity inspects the internal coating of the refueling water storage tanks to check the condition of the coating and to identify coating failures. This program is only applicable to McGuire.

The staff's evaluation of the preventative maintenance activities - refueling water storage tank internal coating inspection program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures and work processes. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope--The applicant defined the scope of the preventative maintenance activities - refueling water storage tank internal coating inspection program as the internal surface of the McGuire carbon steel refueling water storage tanks. The comparable refueling water storage tanks at Catawba are constructed of stainless steel and are managed by the borated water systems stainless steel inspection (Section B.3.4 of the LRA) and the chemistry control program (Section B.3.6 of the LRA).

The staff finds the scope of this aging management program to be acceptable because it includes the tanks that may be subject to coating failure. Limiting the inspection to the refueling water storage tanks at McGuire is acceptable, because the corresponding tanks at Catawba are constructed of different materials and are covered by other programs.

[Preventive or Mitigative Actions] The applicant indicated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff agrees that the inspection program is intended to identify potential problems such that corrective action may be taken prior to loss of component function, and there is no need for preventive actions.

[Parameters Monitored or Inspected] The program inspects the phenolic epoxy paint for signs of blistering, chipping, peeling, and missing paint as well as signs of corrosion of the underlying carbon steel tank. The staff finds the parameters inspected to be acceptable since the inspections are capable of identifying signs of coating damage or deterioration such that corrective actions can be taken prior to loss of component function.

[Detection of Aging Effects] The program uses visual inspection to identify blistering, chipping, peeling, and missing paint as well as signs of corrosion of the underlying carbon steel tank. The staff concludes that these inspections are capable of identifying loss of integrity of the coating and loss of material of the tank prior to loss of the component intended function.

[Monitoring and Trending] Section B.3.24.2 of the LRA states that the refueling water storage tank internal phenolic epoxy paint will be visually inspected every ten years using an underwater video camera. The inspection looks for signs of blistering, chipping, peeling, and missing paint as well as signs of corrosion of the underlying carbon steel tank. Detection of defects in the internal coating results in draining of the tank for further inspection and evaluation of the defects. No actions are taken as part of this activity to trend inspection results.

The staff finds that the monitoring is appropriate for the scope of this inspection. Since the coating is in an area where radiation and thermal conditions are low, degradation of the coating is a slow process, the 10-year frequency is acceptable. The staff finds that the inspection will provide an indication of the condition of the tank coating and is based on methods that are common in the industry. The staff concurs that trending is not required since the inspection frequency is not conducive to trending.

[Acceptance Criteria] The applicant described the acceptance criteria as “no visual indications of coating defects” that have led to corrosion of the underlying carbon steel tank surfaces. The staff agrees that because the visual inspections are capable of detecting degradation of the coating surfaces and the approach is consistent with industry practices, the acceptance criteria are acceptable.

[Operating Experience] The applicant stated that the internal surfaces of the refueling water storage tanks for McGuire were inspected during recent outages using an underwater camera. The inspection revealed some second coating blistering. The applicant drained the tanks, visually inspected, and repainted in the necessary locations. The applicant stated that no bare metal was exposed as a result of the blistering as a layer of coating remained in the blistered location. The applicant observed during these inspections that the submerged portion of the tanks showed little to no degradation. However, the roof, which is not a part of the pressure boundary of the tank, did show evidence of coating concerns and was blasted and repainted in several locations.

The staff finds that the operating experience with program indicates that the activities will be effective in managing loss of material of the tanks by maintaining the effectiveness of the internal coatings. Because of the effectiveness of the inspections, as noted in the operating experience, the staff concludes that the program can reasonably be expected to maintain the tank integrity through the period of extended operation.

FSAR Supplement: In Appendix A-1, Section 18.2.20.2, of the LRA, the applicant provided a proposed new UFSAR section for McGuire. The staff reviewed this material and found it to be consistent with the material provided in Appendix B and, therefore, it is acceptable.

In conclusion, the staff reviewed the information provided in Section B.3.24.2 of the LRA and the summary description in the FSAR Supplement in Appendix A of the LRA. On the basis of this review and the above evaluation, the staff finds that there is reasonable assurance that the aging effect of loss of material of the McGuire refueling water storage tanks will be adequately managed such that the intended function will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on its review of Table 3.2-5 and Appendix B of the LRA, the staff concludes that the above identified AMPs will effectively manage the aging effects of the refueling water system and that there is reasonable assurance that the intended functions of the refueling water system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.6.3 Conclusions

The staff reviewed the information in Section 3.2, "Aging Management of Engineered Safety Features," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant’s characterization of the aging effects associated with the refueling water system is consistent with published literature and industry experience. The staff further concludes that the applicant has appropriate aging management programs to effectively manage the aging effects of the refueling water system and that there is reasonable assurance that the intended functions of the system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.7 Residual Heat Removal System

3.2.7.1 Technical Information in the Application

The applicant described its AMR for the residual heat removal (RHR) system in Section 3.2 of the application. The RHR system transfers heat from the RCS to the Component Cooling System to reduce the temperature of the reactor coolant to the cold shutdown temperature at a controlled rate during the second part of unit cooldown and maintains this temperature until the unit is started up. The RHR system also serve as part of the Emergency Core Cooling System during the injection and recirculation phases of Small-Break and Large-Break Loss of Coolant Accidents. The McGuire and Catawba UFSARs, Section 6.3, Emergency Core Cooling System, provide additional information concerning the RHR system. The mechanical components, component functions, and materials of construction for the RHR system are listed in Table 3.2-7.

3.2.7.1.1 Aging Effects

In Table 3.2-7 of the application, the applicant identifies the following components that are subject to AMR: heat exchangers and their sub-components, piping, orifices, tubing, pump casings, and valve bodies. In this table, the applicant identifies that these components are fabricated from stainless steel materials, with the following exceptions:

- RHR heat exchanger shells and RHR pump seal water shells are fabricated from carbon steel

Loss of material was identified as an applicable aging effect for carbon steel materials exposed to treated and sheltered environments. Loss of material and cracking were identified as applicable aging effects for stainless steel materials exposed to borated and treated water environments.

3.2.7.1.2 Aging Management Programs

The applicant credits the following programs and activities for managing the aging effects attributed for the RHR components:

- chemistry control program
- fluid leak management program
- inspection program for civil engineering structures and components

The applicant stated that it will use the fluid leak management program (Section B.3.15 of the LRA) and the inspection program for civil engineering structures and components (Section B.3.21 of the LRA) to manage loss of material in carbon steel RHR components exposed to sheltered air environments. The applicant also stated that it will use the chemistry control program (Section B.3.6 of the LRA) to manage loss of material and cracking in stainless steel RHR components that are exposed to borated or treated water environments, or loss or material from carbon steel components that are exposed to treated water environments.

3.2.7.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.2. (including Table 3.2-4) and pertinent sections of Appendices A and B to the LRA in order to ascertain that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.7.2.1 Aging Effects

Table 3.2-4 of the application identifies which of these aging effects are applicable to the specific RHR components identified in the table(s) as being within the scope of license renewal. Specifically Table 3.2-4 identifies that the following aging effects are applicable to the material/environmental combinations for the RHR components:

- surfaces of stainless steel components exposed to borated or treated water environments - loss of material and cracking
- stainless steel components in contact with sheltered air or reactor building air environments - no aging effects identified
- surfaces of carbon steel components exposed to external sheltered air environments - loss of material
- surfaces of carbon steel RHR pump seal water components exposed to treated water environments - loss of material
- surfaces of carbon steel RHR heat exchanger components exposed to treated water environments - loss of material and cracking

Industry experience and experimental data have demonstrated that austenitic stainless steel materials may be susceptible to stress corrosion cracking or loss of material (as a result of pitting or general corrosion) when exposed to borated water solutions. Elevated levels of oxidizing impurity species (i.e., oxygen, sulfates, halides, etc.) increase the potential for these aging effects to occur. These aging effects are therefore applicable to the stainless steel RHR components in contact with borated water solutions. The applicant has appropriately identified these aging as being applicable to stainless steel RHR components whose internal surfaces are exposed to borated water. This determination is acceptable to the staff.

Austenitic stainless steel materials are designed to be corrosion resistant in both dry or moist air environments. Cracking and corrosion therefore generally have not been a problem for austenitic stainless steel components in air-gas, sheltered or reactor building environments. The applicant, therefore, has not identified any applicable aging effects for the surfaces of stainless steel RHR components exposed to these types of air environments. Based on these considerations, the staff finds the applicant's identification of the aging effects for stainless steel RHR components to be acceptable.

Use of raw, untreated water in heat exchanger tubes may be prone to biological fouling that could impede the heat exchange functions of the tubes over time. However, raw, untreated water is not the cooling medium for the tubing or the annulus regions of the RHR heat exchangers or RHR pump seal water heat exchangers. The applicant therefore has not identified fouling as an applicable effect for these heat exchangers. The carbon steel RHR heat exchanger shells are in contact with sheltered air environments on their external surfaces, and treated water on their internal surfaces. The internal surfaces of the shell may be subject to loss of material through general corrosion (rusting) when exposed to wet environments. The applicant has also identified cracking as an additional aging effect that requires management for the internal surfaces of the RHR heat exchanger shells.

By letter dated January 23, 2002, the staff informed the applicant that the internal surfaces of the carbon steel residual RHR heat exchanger shells and RHR pump seal water heat exchanger shells are both exposed to treated water environments, and requested, in RAI 3.2-4, the applicant to clarify either by reference to appropriate information in the application or by discussion why cracking is identified as an applicable aging effect for the RHR heat exchanger shells but not for the RHR pump seal water heat exchanger shells.   In its response dated April 15, 2002, the applicant stated that cracking should have been also identified for the internal surfaces of the RHR pump seal water heat exchangers shells and that the Chemistry Control Program is credited as the aging management program for managing the cracking. The applicant submitted a revised Table 3.2-7 AMR for the RHR pump seal water heat exchangers shells to replace the corresponding entry in the LRA. The applicant's resolution of RAI 3.2-4 is, therefore, acceptable to the staff.

Further, the external surfaces of these components may be subject to corrosion if leaks develop. The applicant therefore has appropriately identified that loss of material is an applicable aging effect for the surfaces of the RHR heat exchangers and ND pump seal water heat exchangers shells that are exposed to treated water and sheltered air environments. This determination is acceptable to the staff.

The aging effects identified in LRA Table 3.2-7 are consistent with industry experience for the combinations of materials and environments listed. On the basis of it's review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.2.7.2.2 Aging Management Programs

Table 3.2-7 of the LRA, states that the following programs and activities are credited for managing the aging effects attributed to the RHR components:

- chemistry control program

- fluid leak management program
- inspection program for civil engineering structures and components

The chemistry control program, fluid leak management program, and inspection program for civil engineering structures and components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.2-7, the staff concludes that the above identified AMPs will effectively manage the aging effects of the RHR system and that there is reasonable assurance that the intended functions of the RHR system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.7.3 Conclusions

The staff reviewed the information in Section 3.2, "Aging Management of Engineered Safety Features," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's characterization of the aging effects associated with the RHR is consistent with published literature and industry experience. The staff further concludes that the applicant has appropriate aging management programs to effectively manage the aging effects of the RHR and that there is reasonable assurance that the intended functions of the system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.8 Safety Injection System

3.2.8.1 Technical Information in the Application

The applicant described its AMR for the safety injection system (SIS) in Section 3.2 of the LRA. The SIS constitutes a major portion of the emergency core cooling system (ECCS). Along with the residual heat removal, chemical and volume control, and refueling water systems, the SIS provide emergency cooling water to the reactor core in the event of a break in either the primary (reactor coolant) or secondary (steam) systems. The three primary functions of the ECCS are: (1) to remove stored (sensible) and fission product decay heat; (2) to control reactivity; and (3) to preclude reactor vessel boron precipitation. The SIS support each of these functions. The McGuire/Catawba UFSAR Section 6.3, Emergency Core Cooling System, provides additional information concerning the SIS. The mechanical components, component functions, and materials of construction for the SIS are listed in Table 3.2-8 of the LRA.

3.2.8.1.1 Aging Effects

In Table 3.2-8 of the LRA, the applicant identifies the following components that are subject to AMR: piping, orifices, accumulators, tubing and valve bodies. In the table, the applicant identifies that all of these components are fabricated from stainless steel materials, with the following exceptions:

- a small portion of SIS pipe is fabricated from carbon steel

- SIS accumulators are fabricated from carbon steel with an internal stainless steel cladding
- some SIS valve bodies are fabricated from carbon steel

Loss of material was identified as an applicable aging effect for carbon steel materials exposed to the reactor building and sheltered external environments. Loss of material and cracking were identified as applicable aging effects for stainless steel materials exposed to a borated water environment.

3.2.8.1.2 Aging Management Programs

The applicant credits the following programs and activities for managing the aging effects attributed for the SIS components:

- chemistry control program
- fluid leak management program
- inspection program for civil engineering structures and components

The applicant stated that it will use the fluid leak management program (Section B.3.15 of the LRA) and the inspection program for civil engineering structures and components (Section B.3.21 of the LRA) to manage loss of material in carbon steel SIS components exposed to sheltered air and reactor building environments. The applicant also stated that it will use the chemistry control program (Section B.3.6 of the LRA) to manage loss of material and cracking in stainless steel SIS components that are exposed to borated or treated water environments, or loss or material from carbon steel components that are exposed to treated water environments.

3.2.8.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.2 (including Table 3.2-8) and pertinent sections of Appendices A and B to the LRA in order to ascertain that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.8.2.1 Aging Effects

Table 3.2-8 of the application identifies which of these aging effects are applicable to the specific SIS components identified in the table(s) as being within the scope of license renewal. Specifically Table 3.2-8 identifies that the following aging effects are applicable to the material/environmental combinations for the SIS components:

- surfaces of stainless steel components exposed to borated water environments - loss of material and cracking
- surfaces of carbon steel components whose external surfaces are exposed to reactor building air environments - loss of material

Industry experience and experimental data have demonstrated that austenitic stainless steel materials may be susceptible to stress corrosion cracking or loss of material (as a result of pitting or general corrosion) when exposed to borated water. Elevated levels of oxidizing impurity species (i.e., oxygen, sulfates, halides, etc.) increase the potential for these aging effects to occur. These aging effects are therefore applicable to the stainless steel SIS components in contact with borated water solutions. The applicant has appropriately identified these aging as being applicable to stainless steel SIS components whose internal surfaces are exposed to borated water. This determination is acceptable to the staff.

Austenitic stainless steel materials are designed to be corrosion resistant in both dry or moist air environments. Cracking and corrosion therefore generally have not been a problem for austenitic stainless steel components in air-gas, sheltered or reactor building environments. The applicant, therefore, has not identified any applicable aging effects for internal surfaces of stainless steel SIS components exposed to an air-gas environment, or the external surfaces of stainless steel SIS components exposed to sheltered air or reactor building air environments. Based on these considerations, the staff finds the applicant's identification of the aging effects for stainless steel SIS components to be acceptable.

The carbon steel SIS piping and valve body components are in contact with air-gas environments on their internal surfaces, and either sheltered air or reactor building environments on their external surfaces. Carbon steels may be prone to loss of material by corrosion when exposed to moist air environments. Loss of material therefore may be an applicable aging effect for the surfaces of carbon steel SIS components that are exposed to sheltered or reactor building air environments.
By letter dated January 28, 2002, the staff asked, in RAI 3.2-5, the applicant to clarify either by reference to appropriate information in the application or by discussion why loss of material is identified as an applicable aging effect for the carbon steel SIS piping that is exposed sheltered air but not for the carbon steel SIS valve bodies that are exposed to the same environment. In its response, dated May 15, 2002, the applicant stated that the aging effects for carbon steel valve bodies exposed to sheltered air environments should be identical to those for carbon steel piping exposed to the same environment, and that therefore, loss of material should have been identified for the carbon steel valve bodies exposed externally to sheltered air environments. The applicant provided an amended entry for the SIS carbon steel valve bodies exposed internally to the air-gas environment and externally to sheltered air environment that is consistent with the corresponding entry for carbon steel piping in Table 3.2-8 of the application. This is acceptable to the staff and resolves the staff's issue identified in RAI 3.2-5.

The carbon steel surfaces of the accumulators may be prone to loss of material by corrosion if borated water leak onto the external surfaces of the accumulators. The applicant has appropriately accounted for this as an additional mechanism that can result in loss of material for the carbon steel surfaces of the accumulators. The applicant has not identified any applicable aging effects for the surfaces of carbon steel SIS components that are exposed to air-gas environments. The air-gas environments are compressed dry gaseous environments. Loss of material and cracking generally has not been a problem for carbon steel surfaces that are exposed to air-gas environments. Based on the considerations discussed in this section, the staff considers the applicant's aging effect analysis for the carbon steel SIS components to be acceptable.

The aging effects identified in LRA Table 3.2-8 are consistent with industry experience for the combinations of materials and environments listed. On the basis of it's review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.2.8.2.2 Aging Management Programs

Table 3.2-8 of the LRA states that the following aging management programs are credited for managing the aging effects attributed to the SIS components:

- chemistry control program
- fluid leak management program
- inspection program for civil engineering structures and components

The chemistry control program, fluid leak management program, and inspection program for civil engineering structures and components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.2-8, the staff concludes that the above identified AMPs will effectively manage the aging effects of the SIS and that there is reasonable assurance that the intended functions of the SIS will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.8.3 Conclusions

The staff reviewed the information in Section 3.2, "Aging Management of Engineered Safety Features," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's characterization of the aging effects associated with the SIS is consistent with published literature and industry experience. The staff further concludes that the applicant has appropriate aging management programs to effectively manage the aging effects of the SIS and that there is reasonable assurance that the intended functions of the system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.9 Containment Air Return Exchange and Hydrogen Skimmer Systems - Supplemental Evaluation

In a letter dated January 23, 2002, the staff requested, in RAI 2.3.2.3-2, the applicant to indicate whether or not the McGuire and Catawba containment hydrogen analyzers and their sub-components should be included within the scope of license renewal. In its response to RAI 2.3.2.3-2, dated April 15, 2002, the applicant concurred with the staff that the passive mechanical components for the McGuire and Catawba hydrogen analyzers associated with the hydrogen skimmer systems should be within the scope of license renewal. This section documents the staff's evaluation of the AMR results that were provided for the additional components brought into the scope of license renewal as a result of this RAI.

3.2.9.1 Technical Information in the Application

The containment air return exchange and hydrogen skimmer systems provide the following safety-related functions for the McGuire and Catawba nuclear plants: (1) maintain containment pressure less than the design pressure during any high energy line break (HELB), (2) ensure hydrogen concentration remains less than the flammability limit during a loss-of-coolant-accident (LOCA), and (3) maintain containment isolation integrity for the system piping penetrating the containment. McGuire and Catawba UFSAR Sections 6.2, Containment Systems, provide additional information concerning the McGuire and Catawba containment air return exchange and hydrogen skimmer systems. The mechanical components, component functions, and materials of construction for the McGuire containment air return exchange and hydrogen skimmer systems are listed in Table 3.2-3.

3.2.9.1.1 Aging Effects

In the Table attached to its response to RAI 2.3.2.3-2 the applicant identified that the major flowpaths for the McGuire and Catawba hydrogen analyzers include the following components that are subject to AMRs: tubing and valve bodes for McGuire and Catawba [and McGuire-specific piping]. In this table, the applicant identifies that all of these components are fabricated from stainless steel materials. The applicant identifies that these components are subject to any of the following environments:

- ventilation air
- sheltered air
- reactor building air

The applicant did not identify any additional aging affects associated with the passive mechanical hydrogen analyzer components brought within the scope of license renewal.

3.2.9.1.2 Aging Management Programs

The applicant did not identify any aging management programs necessary for the passive mechanical hydrogen analyzer components brought within the scope of license renewal.

3.2.9.2 Staff Evaluation

3.2.9.2.1 Aging Effects

As summarized in the application, the applicant stated the sheltered and reactor building environments are moist air environments; however, during normal system operations of the systems, any components whose external surface temperatures are the same as or higher than the ambient temperature conditions for these environments are expected to be dry. The applicant states that ventilation air environment is ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy.

Since the internal and external environmental surface conditions for these components should be under either dry or controlled air conditions, the staff concurs that no aging effects are applicable for the stainless steel tubing and valves (and for McGuire, the McGuire-specific stainless steel piping) associated with the hydrogen analyzers.

3.2.9.2.2 Aging Management Programs

Since the environmental surface conditions for these components should be under either dry or controlled air conditions, and no aging effects are applicable for the stainless steel tubing and valves (and for McGuire, the McGuire-specific stainless steel piping) associated with the hydrogen analyzers, the staff concurs that no aging management programs are necessary for the passive mechanical hydrogen analyzer components within the scope of license renewal.

3.2.9.2.3 Conclusions

The staff reviewed the information in Section 3.2 and the table attached to the applicant's response to RAI 2.3.2.3-2, dated April 15, 2002, as the information pertains to the AMRs for the additional hydrogen analyzers components brought within the scope of license renewal. On the basis of its review the staff concludes that the applicant has demonstrated that there are not any aging effects associated with the additional hydrogen analyzers components brought within the scope of license renewal, and that the hydrogen analyzer components brought within the scope of license renewal need not be managed to provide reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.10 Aging Management Review for Closure Bolting in Engineered Safety Feature Systems

Although the LRA provided AMR results for Class 1 bolting, it did not address bolting for Non-Class 1 components. By letter dated January 23, 2002, the staff requested, in RAI 3.2-1, additional information that pertains to tables in Sections 3.2, 3.3, and 3.4 of the LRA that list closure bolting as components subject to AMR. The staff stated that since closure bolting is exposed to air, moisture, and leaking fluid (boric acid) environments, it is subject to the aging effect of loss of material and crack initiation and growth. Tables in Sections 3.2, 3.3 and 3.4 do not address these aging effects for closure bolting in these systems. The staff requested the applicant to identify the AMR results for closure bolting, or to provide a justification for excluding closure bolting from an AMR, the results of which are documented in the referenced tables of the LRA.

3.2.10.1 Aging Effects

The applicant indicated that non-class 1 mechanical components within the scope of license renewal contain bolted closures that are necessary for the pressure boundary of the component. Examples of these bolted closures are valve bonnet to body closures, pump cover to casing closures, heat exchanger manway and end-bell closures and piping flange sets. The bolted closure is comprised of two mating surfaces, a gasket, and a fastener set of studs or bolts and nuts. By themselves, the mating set, gasket, and fastener set have no component intended function. Together, the bolted closure forms an integral part of the pressure-retaining boundary of the component. Gaskets are not relied upon for pressure boundary of the bolted closure in accordance with the design codes and are not subject to an aging management review.

Bolted closures are exposed to two environments. The mating surfaces are exposed internally to the process fluid while the external surfaces and the fastener set are exposed to the ambient environment where the bolted closures are located. Aging effects for external and internal surfaces of the mating set of bolted closures are the same as other components in the system of the same material and exposed to the same environment. Programs for the system (i.e., chemistry in a treated water system and fluid leak management program) containing the bolted closure are applicable to the mating set and are not discussed here further.

The aging effects for the fastener set of non-Class 1 bolted closures are loss of material of carbon and low alloy steel and cracking of carbon, low alloy, and stainless steels. Loss of material of the fastener set of the bolted closure may occur as a result of fluid leakage, use of an improper lubricant during assembly, or exposure to the ambient environment. Cracking of the fastener set of bolted closures may occur as a result of improper material selection, improper torquing during assembly, use of an improper lubricant, fluid leakage, or exposure to the ambient environment. Of these aging effects, Duke determined the following are the aging effects requiring management for carbon and low alloy steel fastener sets:

- loss of material of the fastener set due to boric acid exposure;
- loss of material of the fastener set in systems with operating temperatures below ambient conditions that result in condensation; and
- loss of material of the fastener set in the yard environment that are repeatedly wetted and dried from exposure to the elements.

The applicant stated that no aging effects requiring management were identified for the stainless steel fastener set of bolted closures.

On the basis of its review of the RAI response pertaining to Non-Class 1 bolting, the staff finds that all applicable aging effects were identified, and the aging effects identified are appropriate for the combination of materials and environments listed.

3.2.10.2 Aging Management Programs

The applicant indicated that the Fluid Leak Management Program will manage loss of material of non-Class 1 bolted closures in the Reactor and Auxiliary Buildings due to leakage from systems containing boric acid. No systems containing boric acid are located outside these two buildings. The Fluid Leak Management Program is described in Appendix B, Section B.3.15 of the LRA for McGuire and Catawba.

The Inspection Program for Civil Engineering Structures and Components will manage loss of material of non-Class 1 bolted closures in systems with operating temperatures below the surrounding ambient environment that are wet with condensation. In addition, this program will also manage loss of material of non-Class 1 bolted closures located in the yard that are repeatedly wetted and dried from exposure to the elements. The Inspection Program for Civil Engineering Structures and Components is described in Appendix B, Section B.3.21 of the LRA for McGuire and Catawba.

The Fluid Leak Management program and the Inspection Program for Civil Engineering Structures and considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for Non-Class 1 closure bolting. The staff’s evaluation of these AMPs is documented in Section 3.0 of this SER.

3.2.10.3 Conclusions

Based on the above discussion, the staff finds that the applicant's response clarifies and satisfactorily resolves this issue concerning the closure bolting in mechanical systems as described in RAI 3.2-1. The staff concludes that the applicant has demonstrated that the aging effects associated with Non-Class 1 bolting will be adequately managed so there is reasonable assurance that these components will perform their intended functions consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3 Auxiliary Systems

The applicant described its AMR of the Auxiliary Systems in Section 2.3.3, "Auxiliary Systems," and in Section 3.3, "Aging Management of Auxiliary Systems." Appendices A and B to the LRA also contain supplementary information related to the AMR of the auxiliary systems. The staff reviewed this section of the application in accordance with Chapter 3 of the Standard Review Plan for License Renewal (NUREG-1800) to determine whether the applicant provided adequate information to meet the requirements of 10 CFR Part 54 for managing the aging effects of the Auxiliary Systems for license renewal.

In Section 2.1, "Scoping and Screening Methodology," of the LRA the applicant described the method used to identify the structures and components (SCs) that are within the scope of license renewal and subject to an AMR. The applicant identified and listed the auxiliary system SCs in Section 2.3.3 "Auxiliary Systems," of the LRA. The staff's evaluation of the scoping methodology and the auxiliary system SCs included within the scope of license renewal and subject to an AMR is documented in Sections 2.1 and 2.3.3 of this Safety Evaluation Review (SER), respectively. In Appendix A of the LRA, "Updated Final Safety Analysis Report (UFSAR) Supplement," the applicant provided a summary description of the programs and activities used to manage the effects of aging, as required in 10 CFR 54.21(d). The applicant provided a more detailed description of these AMPs for the staff to use in its evaluation in Appendix B to the LRA. In LRA Appendix D, the applicant states that no changes to the McGuire and Catawba Technical Specifications (TS) have been identified. A discussion of the AMR results for each system follows.

3.3.1 Auxiliary Building Ventilation System

3.3.1.1 Technical Information in the Application

The auxiliary building ventilation system is essentially the same and performs the same function for McGuire and Catawba. The auxiliary building ventilation system automatically aligns to maintain the emergency core cooling system (ECCS) pump rooms at a negative pressure so that air exhausted from these rooms is filtered prior to being released following a design basis accident (DBA). The ECCS pump rooms include safety injection pumps, residual heat removal pumps, centrifugal charging pumps, and containment spray pumps. The McGuire UFSAR and the Catawba UFSAR provide more detailed descriptions in Sections 9.4.2 and 9.4.3 respectively.

3.3.1.1.1 Aging Effects

Components of the auxiliary building ventilation system are described in Section 2.3.3.1 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-1, pages 3.3-6 through 3.3-10, of the LRA lists individual components of the system including the air flow monitors, air handling units, ductwork, filters, demisters, condensers, area heaters, tubing, and valve bodies. Stainless steel components are identified as being subject to ventilation and sheltered environments and are subject to no aging effects. Carbon steel components are subject to the aging effect of loss of material from internal and external surfaces from sheltered and treated water environments. Carbon steel components are also subject to the aging effect of cracking from exposure to a treated water environment. Carbon steel components are also exposed to a gas (Freon-22) environment with no aging effects.

Galvanized steel components are identified as being subject to the aging effect of loss of material from the sheltered environment. Copper components are subject to the aging effect of loss of material and fouling from internal surfaces from raw water environments and external surfaces from loss of material from exposure to sheltered environments. Copper components are also exposed to a ventilation environment with no aging effects. Copper-nickel components are subject to the aging effect of loss of material and fouling from internal surfaces from treated water environments. Copper-nickel components are also exposed to a gas (Freon-22) environment with no aging effects. Brass components are subject to the aging effect of loss of material to external surfaces from sheltered environments. No aging effects are identified to brass components subjected to a ventilation environment.

3.3.1.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the auxiliary building ventilation system:

- Fluid Leak Management Program
- Heat Exchanger Preventive Maintenance Activities - Pump Motor Handling Units
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the auxiliary building ventilation system will be adequately managed by these AMPs during the period of extended operation.

3.3.1.2 Staff Evaluation

The applicant described its AMR of the auxiliary building ventilation system for license renewal in two separate sections of its LRA: Section 2.3.3.1 and Table 3.3-1, pages 3.3-6 through 3.3-10. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the auxiliary building ventilation system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.1.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.1 and Table 3.3-1, pages 3.3-6 through 3.3-10, of the LRA. During its review, the staff determined that additional information was needed to complete it review and, on January 23, 2002, issued RAI 3.3-1. The staff's evaluation of the applicant's response to RAI 3.3-1, pertaining to aging of ventilation system flexible connectors, is documented in Section 3.3.39.3 of this SER and is characterized as resolved.

The staff finds that the aging effects that result from contact of the auxiliary building ventilation system SSCs to the environments described in Section 2.3.3.1 and Table 3.3-1, pages 3.3-6 through 3.3-10, are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects listed are appropriate for the combination of materials and environments listed. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.1.2.2 Aging Management Programs

Section 2.3.3.1 and Table 3.3-1, pages 3.3-6 through 3.3-10, of the LRA states that the following aging management programs are credited for managing the aging effects in the auxiliary building ventilation system components:

- Fluid Leak Management Program
- Heat Exchanger Preventive Maintenance Activities - Pump Motor Handling Units
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components

The Fluid Leak Management Program, Heat Exchanger Preventive Maintenance Activities - Pump Motor Handling Units Program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and, with the exception of open item 3.0.3.9.1.2(a) for the Heat Exchanger Preventive Maintenance Activities - Pump Motor Handling Units, found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-1, the staff concludes that the above identified AMPs will effectively manage the aging effects of the auxiliary building ventilation system and that there is reasonable assurance that the intended functions of the auxiliary building ventilation system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.1.3 Conclusions

The staff reviewed the information in Section 2.3.3.1 and Table 3.3-1 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the auxiliary building ventilation system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2 Boron Recycle System

3.3.2.1 Technical Information in the Application

The boron recycle system is essentially the same and performs the same function for McGuire and Catawba. The boron recycle system receives borated effluent from the RCS and associated support systems. This borated effluent is demineralized, filtered, and separated into 4 weight percent boric acid and reactor makeup water for reuse. The boron recycle system also provides reactor grade flush water for components in the auxiliary and reactor buildings.

The McGuire UFSAR and the Catawba UFSAR provide more detailed descriptions in Sections 9.3.6 and 9.3.5, respectively.

3.3.2.1.1 Aging Effects

Components of the boron recycle system are described in Section 2.3.3.2 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-2, pages 3.3-11 through 3.3-15, of the LRA lists individual components of the system including the eductors, filters, flow meters, orifices, pipes, demineralizers, tanks, strainers, tubing, and valve bodies. Stainless steel components are identified as being subject to cracking and loss of material from exposure to the internal environment of borated and treated water. Exposure of stainless steel to sheltered, air-gas, and reactor building environments have no aging effects. Carbon steel components are subject to the aging effect of loss of material from internal and external surfaces from sheltered and treated water environments. Carbon steel is also subject to a air-gas environment with no aging effect.

3.3.2.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the boron recycle system:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Flow Accelerated Corrosion Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the boron recycle system will be adequately managed by these aging management programs during the period of extended operation.

3.3.2.2 Staff Evaluation

The applicant described its AMR of the boron recycle system for license renewal in two separate sections of its LRA: Section 2.3.3.2 and Table 3.3-2, pages 3.3-11 through 3.3-15. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the boron recycle system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.2 and Table 3.3-2, pages 3.3-11 through 3.3-15, of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3.2-1, the applicant to indicate if Note (3), which implied that portions of the boron recycle system may be subject to alternate wetting and drying, was applicable to Table 3.3-2. In its RAI, the staff further requested the applicant to explain, if Note 3 did apply, how this environment and associated aging effects are managed in the LRA. In its response dated March 15, 2002, the applicant acknowledged that Note (3) did not apply to the boron recycle system and that no components of this system are subject to alternate wetting and drying.

By letter dated January 23, 2002, the staff requested, in RAI-3.3.2-2, the applicant to indicate if Note (1), which contained a definition for a component function of "HT" (heat transfer), applied to Table 3.3-2 for components in the boron recycle system. In its responses, dated March 15, 2002, the applicant acknowledged that Note (1) did not apply to the boron recycle system and that no components of this system have a "HT" or "TH" (throttle) function.

Since the system does not have a “HT” or “TH” function, the staff finds that the applicant's response clarifies and satisfactorily resolves this item. The aging effects that result from contact of the boron recycle system SSCs to the environments described in Section 2.3.3.2 and Table 3.3-2, pages 3.3-11 through 3.3-15, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.2.2.2 Aging Management Programs

Table 3.3-2, pages 3.3-11 through 3.3-15, of the LRA states that the following aging management programs are credited for managing the aging effects in the component cooling system:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Flow Accelerated Corrosion Program

The Fluid Leak Management Program, Chemistry Control Program, Inspection Program for Civil Engineering Structures and Components, and Flow Accelerated Corrosion Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff’s evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-2, the staff concludes that the above identified AMPs will effectively manage the aging effects of the boron recycle system and that there is reasonable assurance that the intended functions of the boron recycle system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3 Conclusions

The staff reviewed the information in Section 2.3.3.2 and Table 3.3-2 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the boron recycle system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.3 Building Heating Water System

3.3.3.1 Technical Information in the Application

The McGuire building heating water system provides normal heating requirements of the auxiliary building ventilation system, fuel pool ventilation system, containment and incore instrumentation room purge system, service building ventilation system, and the turbine building heating system. The Catawba building heating water system supplies hot water to the heating coils of various heating, ventilation, and air conditioning (HVAC) units throughout the plant.

For both McGuire and Catawba, the building heating water system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed. All components within the seismically designed piping boundaries of this system are within the scope of license renewal per 10CFR 54.4(a)(2).

3.3.3.1.1 Aging Effects

Components of the building heating water system are described in Section 2.3.3.3 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-3, page 3.3-16, of the LRA lists individual components of the system including pipes and valve bodies. Stainless steel components are identified as being subject to cracking and loss of material from exposure to the internal environment of treated water. Exposure of stainless steel to sheltered environments has no associated aging effects. Carbon steel components are subject to the aging effect of loss of material from internal surfaces from a treated water environment. Carbon steel is also subject to an aging effect of loss of material from exposure to sheltered environments.

3.3.3.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the building heating water system:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the building heating water system will be adequately managed by these aging management programs during the period of extended operation.

3.3.3.2 Staff Evaluation

The applicant described its AMR of the building heating water system for license renewal in two separate sections of its LRA: Section 2.3.3.3 and Table 3.3-3, page 3.3-16. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the building heating water system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.3.2.1 Aging Effects

The aging effects that result from contact of building heating water system SSCs to the environments described in Section 2.3.3.3 and Table 3.3-3, page 3.3-16, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.3.2.2 Aging Management Programs

Section 2.3.3.3 and Table 3.3-3, page 3.3-16, of the LRA states that the following aging management programs are credited for managing the aging effects in the building heating water system:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components

The Fluid Leak Management Program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-3, the staff concludes that the above identified AMPs will effectively manage the aging effects of the building heating water system and that there is reasonable assurance that the intended functions of the building heating water system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.3.3 Conclusions

The staff reviewed the information in Section 2.3.3.3 and Table 3.3-3, page 3.3-16, of the LRA. On the basis of its review, the staff finds that the applicant has demonstrated that the aging effects associated with the building heating water system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.4 Chemical and Volume Control System

3.3.4.1 Technical Information in the Application

The chemical and volume control system (CVCS) is an integral part of the emergency core cooling system (ECCS) and provides high pressure injection and recirculation of borated water to the RCS cold legs following small and large break loss of coolant accidents and main steam line break accidents. The CVCS is also used to provide negative reactivity, by boron injection, to the core. The McGuire UFSAR and the Catawba UFSAR provide more detailed descriptions in Sections 9.3.4 and 9.3.4 respectively.

3.3.4.1.1 Aging Effects

Components of the chemical and volume control system are described in Section 2.3.3.4 of the submittal as being within the scope of license renewal, and subject to an AMR. Tables 3.3-4 and 3.3-5, pages 3.3-17 through 3.3-37, of the LRA list individual components of the system including pipes, valve bodies, boric acid blenders, filters, tanks, pump casings, meters, resin traps, demineralizers, heat exchangers, orifices, accumulators, stabilizers, spray nozzles, dampeners, and tubing. Stainless steel components are identified as being subject to cracking and loss of material from exposure to the internal and external environments of borated and treated water. Exposure of stainless steel to sheltered, gas, reactor building, and ventilation environments has no aging effects. Carbon steel components are subject to the aging effect of loss of material and cracking from internal environment of treated water. Carbon steel is also subject to an aging effect of loss of material from exposure to sheltered and reactor building environments. Exposure of carbon steel components to an internal gas environment has no aging effect. Cast austenitic stainless steel exposed to a borated environment is subject to the aging effects of cracking and loss of material. Exposure of cast austenitic stainless steel to a reactor building environment has no aging effect identified.

3.3.4.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the chemical and volume control system:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the chemical and volume control system will be adequately managed by these aging management programs during the period of extended operation.

3.3.4.2 Staff Evaluation

The applicant described its AMR of the chemical and volume control system for license renewal in two separate sections of its LRA: Section 2.3.3.4 and Tables 3.3-4 and 3.3-5, pages 3.3-17 through 3.3-37. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the chemical and volume control system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.4.2.1 Aging Effects

The aging effects that result from contact of chemical and volume control system SSCs to the environments described in Section 2.3.3.4 and Tables 3.3-4 and 3.3-5, pages 3.3-17 through 3.3-37, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.4.2.2 Aging Management Programs

Section 2.3.3.4, Tables 3.3-4 and 3.3-5, pages 3.3-17 through 3.3-37, of the LRA states that the following aging management programs are credited for managing the aging effects in the chemical and volume control system:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components

The Fluid Leak Management Program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Tables 3.3-4 and 3.3-5, the staff concludes that the above identified AMPs will effectively manage the aging effects of the chemical and volume control system and that there is reasonable assurance that the intended functions of the chemical and volume control system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.4.3 Conclusions

The staff reviewed the information in Section 2.3.3.4 and Tables 3.3-4 and 3.3-5, pages 3.3-17 through 3.3-37, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the chemical and volume control system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.5 Component Cooling System

3.3.5.1 Technical Information in the Application

The Component Cooling System is essentially the same and performs the same function for McGuire and Catawba. The component cooling system is a closed loop system that maintains cooling to the essential header components as required for plant conditions, maintains an intermediate system pressure boundary between the RCS and the nuclear service water system to prevent potential radioactive release, provides containment isolation, and maintains containment closure for shutdown. The McGuire UFSAR and the Catawba UFSAR provide more detailed descriptions in Sections 9.2.4 and 9.2.2 respectively.

3.3.5.1.1 Aging Effects

Components of the component cooling system are described in Section 2.3.3.5 of the submittal as being within the scope of license renewal, and subject to an AMR. Tables 3.3-6 and 3.3-7, pages 3.3-38 through 3.3-83, of the LRA list individual components of the system including pipes, valve bodies, flex hoses, heat exchangers, condensers, coolers, tanks, orifices, pump casings, and tubing. Stainless steel components are identified as being subject to cracking and loss of material from exposure to the internal and external environments of borated, treated water, and treated water (alternate wet/dry). Exposure of stainless steel to sheltered, reactor building, and ventilation environments have no aging effects. Carbon steel components are subject to the aging effect of loss of material and cracking from internal environment of treated water. Carbon steel is also subject to an aging effect of loss of material to internal surfaces from raw water and external surfaces from exposure to sheltered and reactor building environments. Exposure of carbon steel components to an oil environment has no aging effect. Inconel 625 exposed to a treated water environment is subject to the aging effects of cracking and loss of material.   Exposure of Inconel 625 to reactor building environment has no aging effect. Exposure of cast austenitic stainless steel to a reactor building environment has no aging effect identified. Internal surfaces of admiralty brass components are identified as being subject to the aging effects fouling and loss of material from being exposed to a raw water environment. External surfaces of admiralty brass components a subject to the aging effects of cracking, fouling, and loss of material from exposure to a treated water environment. Copper alloy components are identified as being subject to the aging effects of cracking and loss of material from the environment treated water. Internal surfaces of copper-nickel components are subject to the aging effects of cracking, loss of material, and fouling from exposure to treated water. External surfaces of copper-nickel components exposed to oil and ventilation environments demonstrate no aging effects while those exposed to sheltered environments experience the aging effect of loss of material.

3.3.5.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the component cooling system:

- Performance Testing Activities - Component Cooling Heat Exchanger
- Heat Exchanger Preventive Maintenance Activities - Component Cooling
- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Liquid Waste System Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the component cooling system will be adequately managed by these aging management programs during the period of extended operation.

3.3.5.2 Staff Evaluation

The applicant described its AMR of the component cooling system for license renewal in two separate sections of its LRA: Section 2.3.3.5 and Tables 3.3-6 and 3.3-7, pages 3.3-38 through 3.3-83. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the component cooling system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.5.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.5 and Tables 3.3-6 and 3.3-7, pages 3.3-38 through 3.3-83, of the LRA. During its review, the staff determined that additional information was needed to complete its review. Tables 3.3-6 and 3.3-7 (page 3.3-38 and 3.3-83), indicate that certain reactor coolant (NC) pump motor upper and lower bearing cooler components have a treated water internal environment with an oil external environment. By letter dated January 23, 2002, the staff requested, in RAI 3.3-3, the applicant to indicate where in the LRA the aging effect of loss of material to these components with oil systems subject to water contamination were addressed.

In its response dated March 15, 2002, the applicant stated that all of the lube oil cooler components cited in the first paragraph of RAI 3.3-3 are components of closed oil recirculation systems. Uncontaminated lube oil does not cause aging, and closed oil recirculation systems are assumed to be initially free of contaminants such as water. Further, in the Duke aging management review, component failures were not postulated as a means to establish the relevant conditions required for aging to occur. Therefore, oil cooler tube failures that could introduce water into a lube oil environment were not assumed.

The staff agrees that uncontaminated oil will not cause any aging effect to the components and that the applicant is not required to assume a failure that can cause an aging effect. The staff finds that the applicant’s response to RAI 3.3-3 clarifies and satisfactorily resolves this item. The aging effects that result from contact of component cooling system SSCs to the environments described in Section 2.3.3.5 and Tables 3.3-6 and 3.3-7, pages 3.3-38 through 3.3-83, are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.5.2.2 Aging Management Programs

Tables 3.3-6 and 3.3-7 of the LRA states that the following aging management programs are credited for managing the aging effects in the component cooling system:

- Performance Testing Activities - Component Cooling Heat Exchanger
- Heat Exchanger Preventive Maintenance Activities - Component Cooling
- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Liquid Waste System Inspection

The Fluid Leak Management Program, Chemistry Control Program, Inspection Program for Civil Engineering Structures and Components, and Liquid Waste System Inspection Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff’s evaluation of these AMPs is documented in Section 3.0 of this SER. The staff’s evaluation of the Performance Testing Activities - Component Cooling Heat Exchanger Program and the Heat Exchanger Preventive Maintenance Activities - Component Cooling Program follows.

<u>Performance Testing Activities - Component Cooling Heat Exchangers</u>

The applicant described its component cooling heat exchangers performance testing activities in Section B.3.17.1.1 of Appendix B of the LRA. The staff reviewed the LRA to determine whether the applicant had demonstrated that this program will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

In Section B.3.17.1.1 of Appendix B of the LRA, the applicant stated the purpose of the component cooling heat exchangers performance testing activities and the methods used to monitor and trend the performance of the heat exchangers. The purpose of this program is to manage fouling of admiralty brass and stainless steel heat exchanger tubes that are exposed to raw water. This is a performance monitoring program that monitors specific component parameters to detect the presence of fouling which can affect the heat transfer function of the component.

The staff's evaluation of the performance testing activities-component cooling heat exchangers focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below:

[Scope] The scope of this program includes the McGuire and Catawba component cooling heat exchanger tubes. The staff finds the scope of the program to be acceptable because the information in the application and the applicant's response to the staff's RAI are comprehensive in that they include the components of the component cooling heat exchangers that are subject to an AMR.

[Preventive or Mitigative Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. This is a performance monitoring activity. The staff considers the performance testing activities as a means of detecting, not preventing aging, therefore the staff agrees that there are no preventive measures to be taken or required.

[Parameters Monitored or Inspected] The performance testing activities - component cooling heat exchangers involves monitoring of flow capacity by performance of a differential pressure test to provide an indication of fouling. By letter dated January 28, 2002, the staff requested, in RAI B.3.17-1, additional information from the applicant regarding the flow rates in the component cooling heat exchangers and the susceptibility to flow-induced corrosion. In its response dated March 15, 2002, the applicant indicated that normal or design velocities were reviewed for each heat exchanger to determine whether flow-induced corrosion is applicable. The applicant found that flow-induced corrosion is not an applicable aging effect for any heat exchanger subject to an aging management review. The staff agreed that the differential pressure test is an appropriate method to monitor system performance because it provides a clear indication of tube fouling.

[Detection of Aging Effects] The applicant described the performance testing activities that will be used to detect fouling prior to loss of component heat transfer function. The staff agrees that this testing is appropriate because it will provide information to the applicant prior to loss of component function.

[Monitoring and Trending] The applicant stated that the performance testing activities - component cooling heat exchangers measures the pressure drop through the heat exchanger tubes. An increase in pressure drop indicates the presence of fouling. At McGuire, the applicant indicated that the pressure drop through the heat exchanger tubes is continuously monitored and the pressure drop evaluated against the acceptance criteria. Because the parameter is continuously monitored, the staff finds this acceptable.

At Catawba, a periodic differential pressure test is performed. The test results are trended against a baseline value for indication of tube cleanliness. The frequency of testing at Catawba permits the results of the testing to be trended in order to determine when corrective action is required. The staff reviewed the monitoring and trending activities that are relied on by the applicant and found that they are consistent with current industry practice and, therefore, are acceptable to the staff.

[Acceptance Criteria] At McGuire, where the differential pressure is continuously monitored, the acceptance criteria are in the form of alarm points. An alarm point is provided for high differential pressure and for a high-high differential pressure. At Catawba, the acceptance criterion is in the form of a flow resistance factor value. The acceptable value at both plants is based on a design resistance factor for "clean" heat exchanger tubes. The staff finds both acceptance criteria to be appropriate because they provide the operators with information which will allow action to be taken prior to loss of component function.

[Operating Experience] The applicant reported that operating experience associated with the performance testing activities - component cooling heat exchangers has demonstrated that monitoring of flow through the heat exchangers provides adequate information on the extent of fouling present in the tubes to predict when corrective action is required. Corrective action, in the form of flushing or tube cleaning, for example, is performed before the heat transfer function of the heat exchanger tubes is degraded below its required capacity. The applicant’s experience has demonstrated that both of these techniques permit the fouling to be monitored and any required corrective actions to be performed prior to the heat transfer function being degraded below acceptable limits. The results of trending (at Catawba) for the heat exchanger tube fouling have resulted in the performance of cleaning activities. The applicant has tested different types of cleaning mechanisms (i.e., darts, brushes, high pressure water laze, etc.) in order to maximize the effectiveness of the cleaning. Cleaning activities have restored the condition of the tube surfaces by removal of fouling materials. The applicant has trended the length of time between required cleaning in order to determine the most effective cleaning process and methods.

[Operating Experience] (McGuire) The applicant stated that experience with flow monitoring at McGuire has indicated that the alarm point setting permits action before the differential pressure limit is reached. The applicant reported that the combination of high velocity flushes and better cleaning during outages have almost eliminated on-line cleaning of the heat exchanger tubes. On the basis of the McGuire operating experience, the staff finds that the performance testing activities are capable of identifying and correcting fouling conditions before loss of component function.

[Operating Experience] (Catawba) The applicant stated that experience with the flow tests at Catawba has indicated that the stainless steel tubes foul slightly faster than the original brass tubes. High velocity flushing every six to eight weeks has been used by the applicant and been found potentially effective in reducing fouling and prolonging heat exchanger service between tube cleaning. The staff finds that the applicant's heat exchanger performance monitoring activities for the component cooling heat exchangers operating experience has demonstrated the effectiveness of the program in identifying and correcting fouling prior to loss of component intended function.

FSAR Supplement: In Appendix A-1, Section 18.2.13 and Appendix A-2, Section 18.2.12, the applicant has provided proposed FSAR Supplements for McGuire and Catawba, respectively. The staff reviewed this information and found it to be consistent with the information provided in Appendix B, Section B.3.17 and is therefore acceptable.

In conclusion, the staff reviewed the information in Section B.3.17.1.1 of the LRA and the applicant's response to the staff's request for additional information. On the basis of its review and the above evaluation, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the performance testing activities - component cooling heat exchangers program will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Heat Exchanger Preventive Maintenance Activities - Component Cooling</u>

The applicant described its Heat Exchanger Preventive Maintenance Activities - Component Cooling program in Section B.3.17.1.2 of Appendix B of the LRA. The staff reviewed the LRA to determine whether the applicant had demonstrated that this program will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

Section B.3.17.1.2 of Appendix B of the LRA describes the applicant's preventive maintenance activities for the component cooling water heat exchangers, tubesheets and channel heads. The purpose of these activities is to manage loss of material for parts of the component cooling heat exchanger exposed to raw water. This program is described by the applicant as a condition monitoring program, that monitors specific component parameters to detect the presence and assess the extent of material loss that can affect the pressure boundary function. This program is credited with managing loss of material for admiralty brass, carbon steel and stainless steel materials.

The staff's evaluation of the heat exchanger preventive maintenance activities-component cooling program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope] The applicant described the scope of the heat exchanger preventive maintenance activities - component cooling to include the McGuire and Catawba component cooling heat exchanger tubes, tubesheets, and channel heads. The staff finds this scope to be appropriate because it includes those components important to the proper functioning of the component cooling system heat exchangers.

[Preventive or Mitigative Actions] The applicant did not identify any actions taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff agrees that the purpose of the program is not to prevent loss of material, but to perform inspections which will identify loss of material in the inspected components and allow actions to be taken prior to loss of component function.

[Parameters Monitored or Inspected] The applicant stated that the heat exchanger preventive maintenance activities - component cooling inspects the heat exchanger tubes, tubesheet, and channel head surfaces for loss of material. The staff agrees that inspection of these components will permit actions to be taken prior to loss of component function.

[Detection of Aging Effects] In accordance with the information provided by the applicant under monitoring and trending, the heat exchanger preventive maintenance activities - component cooling will detect loss of material due to crevice, galvanic, general, pitting, and microbiologically influenced corrosion and particle erosion prior to loss of the component pressure boundary function. The staff finds that the inspections are consistent with what is done in the industry, and are capable of detecting aging effects and therefore, the staff finds that the methods are appropriate.

[Monitoring and Trending] The applicant stated that the heat exchanger preventive maintenance activities - component cooling performs eddy current testing on the heat exchanger tubes to measure wall thickness in order to detect areas with loss of material. Trending is performed in order to predict a heat exchanger replacement or repair schedule. The applicant stated that non-destructive testing (NDT) is performed on approximately 50 percent of the tubes of each heat exchanger, at least once every two years, based on operating experience and engineering evaluation of test data.

The applicant stated that with the exception of one Catawba heat exchanger that has no coated components, loss of material of the tube sheets and channel heads of all component cooling heat exchangers is managed by a visual inspection of the protective coatings to assure the integrity of the underlying base metal. This inspection is performed at least once every two years. The tubesheet and channel heads of the component cooling heat exchangers are coated with a high solids epoxy. The coating inspection specifically identifies rust blooms, which indicate a coating defect and corrosion of the base metal. No actions are taken as part of this visual inspection to trend results.

One Catawba component cooling heat exchanger does not currently have any coatings applied to the tubesheets or channel heads. These parts of the heat exchanger are monitored by ultrasonic testing to detect loss of material and the results trended. This inspection is performed as required based on trending results.

As a result of the evaluation, the staff finds that the monitoring and trending activities are appropriate for the components being evaluated, both in scope and frequency. The visual inspections are capable of identifying rust blooms, indicating a coating defect and corrosion of the base metal. The ultrasonic testing is capable of detecting metal loss. Therefore, the staff agrees that the monitoring and trending procedures are appropriate.

[Acceptance Criteria] The applicant identified the acceptance criterion for the heat exchanger preventive maintenance activities - component cooling as no unacceptable loss of material of the tubes, tubesheets, and channel heads that could result in a loss of the component intended function(s) as determined by engineering evaluation. The staff finds that the applicant’s acceptance criterion for this program is not adequate to make a reasonable assurance finding and requests the applicant to specify parameters with quantitative limits (e.g., percent of flow blockage or percent of loss of heat transfer) or provide specific acceptance criteria (e.g., comparison to design criteria, operating requirements, etc.) that are implemented at Catawba and McGuire to allow for actions to be taken prior to a loss of component function. This issue is characterized as open item 3.0.3.9.1.2-1(d).

[Operating Experience] The applicant stated that operating experience associated with the heat exchanger preventive maintenance activities - component cooling has demonstrated that the eddy current testing provides adequate information on the extent of wall loss present in the heat exchanger tubes to predict when corrective action is required. Corrective action in the form of tube plugging, for example, is performed before the loss of the component intended function. The applicant stated and the staff agreed that plant operating experience has demonstrated that measurement and trending of tube wall thickness provides an accurate indication of material condition.

Additionally, the applicant stated that operating experience associated with the heat exchanger preventive maintenance activities - component cooling has demonstrated that protective coatings are effective in preventing loss of material on the tubesheets and channel heads. Inspection of the coatings ensures that the protective features of the coatings are maintained intact. Plant operating experience has demonstrated that visual inspection of the coatings provides an accurate indication of material condition. The applicant's experience prior to application of the coatings and with the tubesheets and channel heads that have not been coated indicates that loss of material may occur without protective coatings.

The applicant's measurement and trending of tubesheet and channel head wall thickness using ultrasonic techniques provides an accurate indication of material condition. The frequency of monitoring permits the results to be trended in order to determine when corrective action is required.

Based on the review of the applicant’s operating experience, the staff finds that the inspections and monitoring activities have demonstrated that the techniques being used allow for the trending of the loss of material and any required corrective actions to be performed before the loss of component intended function.

FSAR Supplement: In Appendix A-1, Section 18.2.13 and Appendix A-2, Section 18.2.12, the applicant provided proposed FSAR Supplements for McGuire and Catawba, respectively. The staff reviewed this information and found it to be consistent with the information provided in Appendix B, Section B.3.17 and is therefore acceptable.

The staff has reviewed the information in Section B.3.17.1.2 of the LRA. On the basis of this review and the above evaluation, with the exception of open item 3.0.3.9.1.2-1(d) pertaining to acceptance criteria for the heat exchanger preventive maintenance activities, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the preventive maintenance activities - component cooling heat exchangers program will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on its review of Tables 3.3-6 and 3.3-7 and Appendix B of the LRA, with the exception of open item 3.0.3.9.1.2-1(d) pertaining to acceptance criteria for the heat exchanger preventive maintenance activities, the staff concludes that the above identified AMPs will effectively manage the aging effects of the component cooling system and that there is reasonable assurance that the intended functions of the component cooling system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.5.3 Conclusions

The staff reviewed the information in Section 2.3.3.5; Tables 3.3-6 and 3.3.7; and Section B.3.17 of the LRA. On the basis of its review, with the exception of open item 3.0.3.9.1.2-1(d) pertaining to acceptance criteria for the heat exchanger preventive maintenance activities, the staff concludes that the applicant has demonstrated that the aging effects associated with the component cooling system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.6 Condenser Circulating Water System

3.3.6.1 Technical Information in the Application

The condenser circulating water system provides a suction source of water to the turbine-driven auxiliary feedwater pump for events requiring the activation of the standby shutdown facility. The McGuire UFSAR and the Catawba UFSAR provide more detailed descriptions in Sections 10.4.5 and 10.4.5 respectively.

3.3.6.1.1 Aging Effects

Components of the condenser circulating water system are described in Section 2.3.3.6 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-8, pages 3.3-84 through 3.3-86, of the LRA lists individual components of the system including pipes, valve bodies, pump casings, and strainers. Carbon steel components are subject to the aging effect of loss of material from internal surfaces from a raw water environment. External surfaces of carbon steel are also subject to the aging effect of loss of material from exposure to sheltered, underground, and yard environments. Carbon steel in an embedded environment is not subject to any aging effect.

3.3.6.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the condenser circulating water system:

- Galvanic Susceptibility Inspection
- Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection
- Inspection Program for Civil Engineering Structures and Components

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the condenser circulating water system will be adequately managed by these aging management programs during the period of extended operation.

3.3.6.2 Staff Evaluation

The applicant described its AMR of the condenser circulating water system for license renewal in two separate sections of its LRA: Section 2.3.3.6 and Table 3.3-8, pages 3.3-84 through 3.3-86. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the condenser circulating water system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.6.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.6 and Table 3.3-8, pages 3.3-84 through 3.3-86, of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3-4, additional information pertaining to Table 3.3-8. In Table 3.3-8, the applicant indicates that Catawba and McGuire carbon steel condenser circulating water system components are subject to an internal environment of raw water. The staff requested that the applicant confirm that strainers do not perform a component function that may be degraded by the aging effect of fouling, neither of which is identified in Table 3.3-8 for strainers in a raw water environment. Similarly, staff requested that the applicant confirm that neither orifices nor strainers, identified in Table 3.3-36, Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station), and Table 3.3-37, Aging Management Review Results - Nuclear Service Water System (Catawba Nuclear Station), perform a component function that may be degraded by the aging effect of fouling from exposure to raw water.

In its response dated March 15, 2002, the applicant stated that the strainers in the condenser circulating water system (Table 3.3-8 for both McGuire and Catawba) and in the nuclear service water system (Table 3.3-36 for McGuire and 3.3-37 for Catawba) have a component intended function to maintain pressure boundary integrity. The component intended function of the strainer to maintain pressure boundary integrity will not be degraded by fouling. The orifices in the nuclear service water system (Table 3.3-36 for McGuire and 3.3-37 for Catawba) have two component intended functions: (1) to maintain pressure boundary integrity and (2) to throttle flow. Fouling will not degrade either the pressure boundary function or the throttling function of the orifices. The staff agrees with the applicant that fouling is not an applicable aging effect since the system does not perform a heat transfer function. The staff finds that the applicant's response clarifies and satisfactorily resolves this item.

In its April 15, 2002, response to RAI 2.3.3.6-6, the applicant determined that expansion joints on the discharge of the condenser cooling water pumps were within the scope of license renewal (see Section 2.3.3.6.2 of this SER). The following AMR results for these components were provided in the applicant's response:

Component Type	Component Function	Material	Internal Environment External Environment	Aging Effect	Aging Management Programs and Activities
Expansion Joints	PB	Synthetic Rubber*	Raw Water Yard	None Identified None Identified	None Required None Required

* A woven polyester and/or nylon fabric coated with chlorobutyl rubber.

The applicant indicated that external surfaces of these expansion joints are exposed to a "yard" environment and "no" aging effects are identified. The staff believes that there is potential degradation to the expansion joints if they are exposed to extensive UV rays in a yard environment. If these expansion joints are in a vault, shaded or covered, then the staff agrees that there is no aging effects to the expansion joints. The definition of the yard environment provided in the LRA does not address sunlight exposure. Pending the staff's receipt of the specific yard environment for these expansion joints, this issue is characterized as open item 3.3.6.2.1-1.

The aging effects that result from contact of condenser circulating water system SSCs to the environments described in Section 2.3.3.6 and Table 3.3-8, pages 3.3-84 through 3.3-86, are consistent with industry experience for these combinations of materials and environments. On the basis of it's review, with the exception of open item 3.3.6.2.1-1, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.6.2.2 Aging Management Programs

The aging management programs identified in Section 2.3.3.6 and Table 3.3-8, pages 3.3-84 through 3.3-86, of the LRA have been evaluated and found to be acceptable for managing the aging effects identified for the condenser circulating water system.

- Galvanic Susceptibility Inspection
- Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection
- Inspection Program for Civil Engineering Structures and Components

The Galvanic Susceptibility Inspection Program, Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and, with the exception of open item 3.0.3.13.2-1 for the Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection program (see Section 3.0.3.13.2 of this SER), found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-8, with the exception of open item 3.0.3.13.2-1 for the Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection program, the staff concludes that the above identified AMPs will effectively manage the aging effects of the condenser circulating water system and that there is reasonable assurance that the intended functions of the condenser circulating water system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.6.3 Conclusions

The staff reviewed the information in Section 2.3.3.6 and Table 3.3-8 of the LRA. On the basis of its review, with the exception of open items 3.3.6.2.1-1 and 3.0.3.13.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the condenser circulating water system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.7 Containment Ventilation System

3.3.7.1 Technical Information in the Application

The McGuire upper and lower containment ventilation system provide cooling to the upper and lower compartments of containment during normal operation and shutdown. The upper and lower containment ventilation systems contain resistance temperature detectors (RTDs) that are required for post-accident monitoring in accordance with the environmental qualification rule. The staff's review of the applicant environmental qualification program is documented in Section 4.4 of this SER. No mechanical components have an intended function; therefore, no aging management review is required.

3.3.7.2 Staff Evaluation

The applicant described its AMR of the containment ventilation system for license renewal in LRA Section 2.3.3.7. The staff reviewed this section of the LRA to determine whether the applicant had demonstrated that the effects of aging on the containment ventilation system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff finds that aging management is not applicable to this section since there are no mechanical functions provided by any of the components that meet the scoping criteria of 10 CFR 54.4.

3.3.7.3 Conclusion

The staff concludes that, since there are no mechanical functions provided by any of the components that meet the scoping criteria of 10 CFR 54.4, an AMR is not required for this system.

3.3.8 Control Area Ventilation System and Chilled Water System

3.3.8.1 Technical Information in the Application

The control area ventilation system and control area chilled water systems combine to form one system to provide the normal and emergency ventilation requirements to the control room and control room area. The McGuire UFSAR and the Catawba UFSAR provide more detailed descriptions in Sections 6.4 and 9.4.1 respectively.

3.3.8.1.1 Aging Effects

Components of the control area ventilation system and control area chilled water systems are described in Section 2.3.3.8 of the submittal as being within the scope of license renewal, and subject to an AMR. Tables 3.3-9, 3.3.10, and 3.3.11, pages 3.3-87 through 3.3-113, of the LRA lists individual components of the system including pipes, valve bodies, pump casings, strainers, tubing, orifices, flow indicators, refrigerant filters, y-strainers, compression tanks, storage tanks, condenser shells, condenser tubes, tube sheets, channel heads, oil separators, oil filters, economizers, evaporator tubes, evaporator tube sheets, chemical feeders, ductwork, filter trains, and evaporator heads. Carbon steel components are subject to the aging effect of loss of material and cracking of internal surfaces from a treated water environment. Internal surfaces of carbon steel are also subject to loss of material due to exposure to raw water. External surfaces of carbon steel are also subject to an aging effect of loss of material from exposure to sheltered environments. Exposure of internal or external carbon steel surfaces to gas or oil environments have no aging effects. Internal surfaces of stainless steel components are subject to the aging effect of loss of material and cracking due to exposure to a treated water environment. Exposure of internal or external surfaces of stainless steel components to a sheltered, gas or oil environments has no aging effect. Cast iron components exposed to an internal environment of treated water are subject to the aging effect of loss of material, while external surfaces exposed to sheltered environments are also subject to the aging effect of loss of material. Exposure of cast iron to a gas or oil environment has no aging effect. Internal surfaces of copper-nickel components are subject to the aging effects of fouling and loss of material from exposure to raw water environment. Internal surfaces of copper-nickel components also experience the aging effect of loss of material due to exposure to a treated water environment. External surfaces of copper-nickel components exposed to a gas environment experience no aging effects. Components made of copper exposed to a treated water environment experience the aging effects fouling and loss of material. Exposure of copper components to a gas environment results in no aging effect. Components made of admiralty brass exposed to a treated water environment experience the aging effects of cracking and loss of material. Exposure of copper components to an oil environment experiences no aging effect. There are no aging effects to the internal surfaces of galvanized steel and brass components exposed to a ventilation environment. Exposure of external surfaces of galvanized steel and brass components to a yard and sheltered environment also experiences no aging effect.

3.3.8.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the control area ventilation systems:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Heat Exchanger Preventive Maintenance Activities - Control Area Chilled Water
- Service Water Piping Corrosion Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the control area ventilation system will be adequately managed by these aging management programs during the period of extended operation.

3.3.8.2 Staff Evaluation

The applicant described its AMR of control area ventilation system and control area chilled water systems for license renewal in four separate sections of its LRA: Section 2.3.3.8 and Tables 3.3-9, 3.3.10, and 3.3.11, pages 3.3-87 through 3.3-113. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the control area ventilation system and control area chilled water systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.8.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.8 and Tables 3.3-9, 3.3.10, and 3.3.11, pages 3.3-87 through 3.3-113, of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAIs 3.3-1 and 3.3-3, additional information from the applicant. The staff's evaluation of the applicant's response to RAI 3.3-1, pertaining to aging of ventilation system flexible connectors, is documented in Section 3.3.39.3 of this SER and is characterized as resolved.

In RAI 3.3-3, the staff requested the applicant to address information provided in Tables 3.3-9 (pages 3.3-91 to 3.3-93) and 3.3-10 (pages 3.3-103 to 3.3-104). These tables indicate that certain Catawba and McGuire control room area chiller components (oil cooler tubes, tube sheets and shells) are subject to an internal/external environment of treated water/oil. In RAI 3.3-3, the staff requested the applicant identify where in the LRA the aging effect of loss of material for these components in oil systems subject to water contamination was addressed.

In its response dated March 15, 2002, the applicant stated that all of the lube oil cooler components cited in the first paragraph of RAI 3.3-3 are components of closed oil recirculation systems. Uncontaminated lube oil does not cause aging, and closed oil recirculation systems are assumed to be initially free of contaminants such as water. Further, in the Duke aging management review, component failures were not postulated as a means to establish the relevant conditions required for aging to occur. Therefore, in oil coolers, tube failures that could introduce water into a lube oil environment are not assumed. The staff agrees that uncontaminated oil will not cause any aging effect to the components and that the applicant is not required to assume a failure that can cause an aging effect. The staff finds that the applicant's response to RAI 3.3-3 clarifies and satisfactorily resolves this item.

The aging effects that result from contact of the control area ventilation system SSCs to the environments described in Section 2.3.3.8 and Tables 3.3-9, 3.3.10, and 3.3.11, pages 3.3-87 through 3.3-113, are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects listed are appropriate for the combination of materials and environments listed. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.8.2.2 Aging Management Programs

Section 2.3.3.8 and Tables 3.3-9, 3.3.10, and 3.3.11, pages 3.3-87 through 3.3-113, of the LRA states that the following aging management programs are credited for managing the aging effects in the component cooling system:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Heat Exchanger Preventive Maintenance Activities - Control Area Chilled Water
- Service Water Piping Corrosion Program

The Fluid Leak Management Program, Chemistry Control Program, Service Water Piping Corrosion Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and, with the exception of open item 3.0.3.15.2-1 pertaining to the service water piping corrosion program, found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. The staff's evaluation of Heat Exchanger Preventive Maintenance Activities - Control Area Chilled Water Program follows.

<u>Heat Exchanger Preventive Maintenance Activities - Control Area Chilled Water Program</u>

The applicant described its preventive maintenance activities of the control area chilled water heat exchangers in Section B.3.17.4 of Appendix B of the LRA. The staff reviewed the LRA to determine whether the applicant had demonstrated that this program will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

The applicant provided a discussion of the preventive maintenance activities of the control area chilled water heat exchangers in Section B.3.17.4 of Appendix B of the LRA. The applicant stated that the purpose of this program is to manage fouling and loss of material of parts of the control room area chillers exposed to raw water. This is defined by the applicant as a condition monitoring program that monitors specific component parameters to detect the presence and assess the extent of material loss that can affect the pressure boundary functions and periodically cleans the chiller tubes to manage fouling. The applicant credited the heat exchanger preventive maintenance activities - control area chilled water program with managing loss of material or fouling for admiralty brass, carbon steel, and stainless steel materials.

The staff's evaluation of the preventive maintenance testing activities of the control area chilled water heat exchangers program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope] The applicant defined the scope of the Heat Exchanger Preventive Maintenance Activities - Control Area Chilled Water program to include the McGuire and Catawba control room chiller condenser tubes and channel heads. The staff finds the scope to be acceptable because it includes those components important to assuring that the pressure boundary is maintained.

[Preventive or Mitigative Actions] The applicant stated that there are no actions taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff agreed that this program is designed to monitor and inspect the components and therefore preventive or mitigative actions are not required.

[Parameters Monitored or Inspected] The applicant stated that the program inspects the chiller tubes and channel heads to provide an indication of loss of material. The staff finds the inspection parameters to be acceptable because they will permit the applicant to receive early warning of potential loss of wall material in the tubes.

[Detection of Aging Effects] The applicant stated that in accordance with the information provided under the Monitoring and Trending section, the heat exchanger preventive maintenance activities - control area chilled water program will detect loss of material due to crevice, galvanic, general, pitting, and microbiologically influenced corrosion and particle erosion prior to loss of the component's pressure boundary function. The applicant stated that the program will also manage fouling prior to the loss of the heat transfer function. The staff agreed that the program is capable of detecting loss of material to allow for corrective actions to be taken prior to the loss of function and therefore finds this to be acceptable.

[Monitoring and Trending] The applicant stated that the heat exchanger preventive maintenance activities - control area chilled water performs eddy current testing on the heat exchanger tubes to measure wall thickness in order to detect areas with loss of material. The applicant performs NDT on approximately 50 percent of the control room chiller condensers at least every five years. The applicant then performs an analysis following each NDT to determine the need for further testing, replacement, or repair.

The applicant stated that fouling of the internal portions of the chiller tubes exposed to raw water is managed by routine cleaning. At least annually, the tubes are rodded out and cleaned. No action is taken as part of this activity to trend inspection results. The applicant stated that loss of material of the channel heads is managed by an annual visual inspection of the protective coatings to assure the integrity of the underlying base metal. The channel heads of the control room area chillers are coated with a high solids epoxy. The coating inspection specifically identifies rust blooms, which indicate a coating defect and corrosion of the base metal. No action is taken as part of this activity to trend inspection results.

The staff finds that the monitoring and inspection activities are acceptable because they are capable of identifying loss of material to allow for corrective action to be taken prior to loss of component function. The applicant does not trend the results of the inspections and the staff did not identify a need for such trending because actions are taken based on inspection findings.

[Acceptance Criteria] The applicant stated that the acceptance criteria for the control area chilled water heat exchanger preventive maintenance activities program is no unacceptable loss of material of the tubes and channel heads that could result in a loss of the component's intended function(s) as determined by engineering evaluation. The staff does not consider this an adequate acceptance criterion for the heat preventive maintenance activities AMP. In addressing the acceptance criteria, the staff requests the applicant to specify parameters with quantitative limits (e.g., percent of flow blockage or percent of loss of heat transfer). Therefore, this issue is characterized as open item 3.0.3.9.1.2-1(e).

[Operating Experience] The applicant stated that operating experience associated with the heat exchanger preventive maintenance activities - control area chilled water program has demonstrated that the eddy current testing provides adequate information on the extent of wall loss present in the chiller tubes to predict when corrective action is required. Corrective action, in the form of tube plugging, for example, is performed before the loss of component intended function.

The applicant stated that periodic tube cleaning has proven to be an effective method of managing fouling of the tubes that could lead to loss of heat transfer. The applicant stated that the control area chiller operates during normal plant operation. The applicant's routine surveillance of the chiller's operating parameters indicated that periodic cleaning is effective in managing fouling of the chiller tubes. The applicant stated that experience prior to the application of the coatings of the carbon steel channel heads indicated that loss of material was occurring. Due to the inspection results, the applicant recently coated the channel heads. Future inspection of the coatings should allow the applicant to ensure that the protective features of the coatings are maintained intact.

The applicant's operating experience has demonstrated that heat exchanger preventive maintenance activities - control area chilled water program is an effective program for managing the effects of aging. The program with its proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls, accurately predicts aging effects due to corrosion and erosion.

The staff finds that the applicant is properly making use of the operating experience with the heat exchanger preventive maintenance activities - control area chilled water program and has demonstrated the ability of the program to properly manage aging effects of the chiller tubes.

FSAR Supplement: In Appendix A-1, Section 18.2.13 and Appendix A-2, Section 18.2.12, the applicant provided proposed FSAR Supplements for McGuire and Catawba, respectively. The staff reviewed this information and found it to be consistent with the information provided in Appendix B, Section B.3.17 and is therefore acceptable.

During its review of information in Section 2.3.3.8; Tables 3.3-9, 3.3-10, and 3.3-11, pages 3.3-87 through 3.3-113; and Section B.3.17 of the LRA, the staff identified the need for additional information pertaining to this AMP. In Tables 3.3-9 and 3.3-10 of the LRA, the applicant indicates that the heat exchanger preventive maintenance activities-control area chilled water program is credited for managing the aging effects of fouling and loss of material for copper-nickel alloy materials. The heat exchanger preventive maintenance activities-control area chilled water program, as defined in Appendix B of the LRA, manages the loss of material or fouling for admiralty brass, carbon steel, and stainless steel materials; but the description in Appendix B does not include the material copper-nickel with the scope of the heat exchanger preventive maintenance activities-control area chilled water program. By letter dated January 23, 2002, the staff requested, in RAI 3.3.9-1, that the applicant explain how the heat exchanger preventive maintenance activities-control area chilled water program manages for the loss of material or fouling for copper-nickel alloy materials, or provide an AMP for managing these aging effects for this material.

In its response dated March 15, 2002, the applicant stated that the heat exchanger preventive maintenance activities - control area chilled water program, as described in Section B.3.17.4 of Appendix B, is credited for managing fouling and loss of material for the copper-nickel alloy tubes. The copper-nickel alloy material was inadvertently omitted from the introductory paragraph in the program description in Appendix B of the application. The program description does describe how fouling and loss of material of the copper-nickel alloy heat exchanger tubes are managed. The applicant further stated that McGuire FSAR Supplement Section 18.2.13.4 and Catawba FSAR Supplement Section 18.2.12.4 will be revised to indicate that the heat exchanger preventive maintenance activities - control area chilled water program is credited for managing loss of material or fouling for admiralty brass, carbon steel, copper-nickel alloy, and stainless steel materials. Since the applicant will add fouling as an aging effect to the copper-nickel alloy components, the staff finds that the applicant’s response clarifies and satisfactorily resolves this item.

The staff has reviewed the information in Section B.3.17.4 of the LRA. On the basis of this review and the above evaluation, with the exception of open item 3.0.3.9.1.2-1(e) pertaining to acceptance criteria for the heat exchanger preventive maintenance activities, the staff finds that the applicant has demonstrated that the effects of aging associated with the preventive maintenance activities - control area chilled water heat exchangers program will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on its review of Tables 3.3-9, 3.3-10, and 3.3-11 and Appendix B of the LRA, with the exception of open item 3.0.3.9.1.2-1(e) pertaining to acceptance criteria for the heat exchanger preventive maintenance activities and open item 3.0.3.15.2-1 pertaining to the service water piping corrosion program, the staff concludes that the above identified AMPs will effectively manage the aging effects of the control area ventilation system and control area chilled water systems and that there is reasonable assurance that the intended functions of these systems will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.8.3 Conclusions

The staff reviewed the information in Section 2.3.3.8; Tables 3.3-9, 3.3-10 and 3.3-11; and section B.3.17 of the LRA. On the basis of its review, with the exception of open items 3.0.3.9.1.2-1(e) and 3.0.3.15.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the control area ventilation system and control area chilled water systems will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.9 Conventional Waste Water Treatment System

3.3.9.1 Technical Information in the Application

The McGuire conventional wastewater treatment system maintains water level in the standby shutdown facility (SSF) sump to prevent flooding of the SSF equipment.   The McGuire UFSAR provides a more detailed description in Section 9.2.8.

3.3.9.1.1 Aging Effects

Components of the conventional wastewater treatment system are described in Section 2.3.3.9 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-12, pages 3.3-114 through 3.3-115, of the LRA lists individual components of the system including pipe, pump casings, and valve bodies. Internal surfaces of carbon steel and cast iron components exposed to a raw water environment are subject to the aging effect, loss of material. External surfaces of carbon steel and cast iron components exposed to sheltered environments are subject to the aging effect, loss of material. Embedded carbon steel components experience no aging effects.

3.3.9.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the conventional wastewater treatment system:

- Galvanic Susceptibility Inspection
- Sump Pump System Inspection
- Inspection Program for Civil Engineering Structures and Components
- Selective Leaching Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the conventional wastewater treatment system will be adequately managed by these aging management programs during the period of extended operation.

3.3.9.2 Staff Evaluation

The applicant described its AMR of the conventional wastewater treatment system for license renewal in two separate sections of its LRA: Section 2.3.3.9 and Table 3.3-12, pages 3.3-114 through 3.3-115. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the conventional wastewater treatment system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.9.2.1 Aging Effects

The aging effects that result from contact of the conventional wastewater treatment system SSCs to the environments described in Section 2.3.3.9 and Table 3.3-12, pages 3.3-114 through 3.3-115, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.9.2.2 Aging Management Programs

Section 2.3.3.9 and Table 3.3-12, pages 3.3-114 through 3.3-115, of the LRA states that the following aging management programs are credited for managing the aging effects in the conventional wastewater treatment system:

- Galvanic Susceptibility Inspection
- Sump Pump System Inspection
- Inspection Program for Civil Engineering Structures and Components
- Selective Leaching Inspection

The Galvanic Susceptibility Inspection Program, Sump Pump System Inspection Program, Inspection Program for Civil Engineering Structures and Components, and Selective Leaching Inspection Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff’s evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-12, the staff concludes that the above identified AMPs will effectively manage the aging effects of the conventional waste water treatment system and that there is reasonable assurance that the intended functions of the conventional waste water treatment system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.9.3 Conclusions

The staff reviewed the information in Section 2.3.3.9 and Table 3.3-12, pages 3.3-114 through 3.3-115, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the conventional wastewater treatment system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.10 Diesel Building Ventilation System

3.3.10.1 Technical Information in the Application

The diesel building ventilation system maintains temperature control for each diesel building when its associated diesel generator is running. The McGuire UFSAR and the Catawba UFSAR provide more detailed descriptions in Sections 9.4.6 and 9.4.4 respectively.

3.3.10.1.1 Aging Effects

Components of the diesel building ventilation system are described in Section 2.3.3.10 of the submittal as being within the scope of license renewal, and subject to an AMR. Table 3.3-13, pages 3.3-116 through 3.3-117, of the LRA lists individual components of the system including pipe, tubing, ductwork, and valve bodies. External surfaces of carbon steel components are subject to the aging effect, loss of material, from exposure to sheltered environments. Exposure of internal and external surfaces of stainless steel, brass, galvanized steel and copper components to ventilation and sheltered environments are subject to no aging effects. There is no boric acid contamination to this building. Therefore, galvanized steel and copper components exposed to ventilation and sheltered environments are not subject to any aging effects.

3.3.10.1.2 Aging Management Programs

The following AMP is utilized to manage aging effects to the diesel building ventilation system:

- Inspection Program for Civil Engineering Structures and Components

A description of the aging management program is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the diesel building ventilation system will be adequately managed by the aging management program during the period of extended operation.

3.3.10.2 Staff Evaluation

The applicant described its AMR of the diesel building ventilation system for license renewal in two separate sections of its LRA: Section 2.3.3.10 and Tables 3.3-13, pages 3.3-116 through 3.3-117. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on diesel building ventilation system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.10.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.10 and Table 3.3-13, pages 3.3-116 through 3.3-117, of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff asked, in RAI 3.3-1, the applicant to indicate why AMR results tables for with numerous ventilation systems in LRA Section 3.3 do not list elastomer components associated with duct seals, flexible collars between ducts and fans, rubber boots, etc. The staff's evaluation of the applicant's April 15, 2002, response to RAI 3.3-1, pertaining to aging of ventilation system flexible connectors, is documented in Section 3.3.39.3 of this SER and is characterized as resolved.

The aging effects that result from contact of the diesel building ventilation system SSCs to the environments described in Section 2.3.3.10 and Table 3.3-13, pages 3.3-116 through 3.3-117, are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects listed are appropriate for the combination of materials and environments listed. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.10.2.2 Aging Management Programs

Section 2.3.3.10 and Tables 3.3-13, pages 3.3-116 through 3.3-117, of the LRA states that the following aging management program is credited for managing the aging effects in the diesel building ventilation system:

- Inspection Program for Civil Engineering Structures and Components

The Inspection Program for Civil Engineering Structures and Components is credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-13, the staff concludes that the above identified AMP will effectively manage the aging effects of the diesel building ventilation system and that there is reasonable assurance that the intended functions of the diesel building ventilation system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.10.3 Conclusions

The staff reviewed the information in Section 2.3.3.10 and Table 3.3-13 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel building ventilation system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.11 Diesel Generator Air Intake and Exhaust System

3.3.11.1 Technical Information in the Application

The diesel generator air intake and exhaust system is essentially the same and performs the same function for McGuire and Catawba. The diesel generator air intake and exhaust system supplies sufficient air to the diesel generator engines for fuel consumption and removes exhaust from the diesel generator engines to the atmosphere outside the building. The McGuire UFSAR Section 9.5.11, Diesel Generator Air Intake and Exhaust System, provides additional information concerning the McGuire diesel generator air intake and exhaust system. The Catawba UFSAR Section 9.5.8, Diesel Generator Air Intake and Exhaust System, provides additional information concerning the Catawba diesel generator engine air intake and exhaust system.

3.3.11.1.1 Aging Effects

Components of the diesel generator air intake and exhaust system are described in Section 2.3.3.11 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-14, pages 3.3-118 through 3.3-120, of the LRA lists individual components of the system including exhaust silencers, filters, flexible connectors, expansion joints, hoses, tubing, pipes, and valve bodies. Stainless steel components are identified as being subject to the internal and ventilation environment and sheltered with no aging effects identified. Carbon steel components are subject to the aging effect of loss of material from external surfaces from sheltered and yard environments. Carbon steel components are identified as being subject to the internal environment of ventilation with no aging effects identified. Rubber and composite rubber components exposed to internal and ventilation environment and sheltered have no identified aging effects.

3.3.11.1. Aging Management Programs

The following AMP is utilized to manage aging effects to the diesel generator air intake and exhaust system:

- Inspection Program for Civil Engineering Structures and Components

A description of the aging management program is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the diesel generator air intake and exhaust system will be adequately managed by the aging management program during the period of extended operation.

3.3.11.2 Staff Evaluation

The applicant described its AMR of the diesel generator air intake and exhaust system for license renewal in two separate sections of its LRA: Section 2.3.3.11 and Table 3.3-14, pages 3.3-118 through 3.3-120. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the diesel generator air intake and exhaust system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.11.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.11 and Table 3.3-14, pages 3.3-118 through 3.3-120, of the LRA. During its review, the staff determined that additional information was needed to complete its review and , on January 23, 2002, issued RAIs 3.3-5, 3.3.14-1 and 3.3.14-2. The staff's evaluation of the applicant's responses is provided below.

In the LRA, the applicant stated that all of the components in Table 3.3-14, "Aging Management Review for Diesel Generator Air Intake and Exhaust System," are subject to an interior environment of ventilation, which is defined as ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy. CN-1609-5.0, CN-2609-5.0, MCFD-1609-5.00 and MCFD-2609-5.00, "Flow Diagrams for Diesel Engine Air Intake and Exhaust System," do not include equipment to condition the intake air or the exhaust air for the diesels to provide a ventilation internal environment. Typically these components are subject to a sheltered internal environment. Similarly, Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator, Exhaust Sub-System," components are subject to an internal environment of ventilation, which is defined as ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy. CN-1560-1.0, CN-1560.20, MCFD-1560-1.00, MCFD-1560.20, and MCFD-1614-4, "Flow Diagrams for Standby Shutdown Diesel System," do not include equipment to condition the intake air or the exhaust air for the diesels to provide a ventilation internal environment. Typically, these components are subject to a sheltered internal environment. In RAI 3.3-5, the staff requested that the applicant provide justification for classifying the internal environment for these components as "ventilation."

In its response to RAI 3.3-5, dated March 15, 2002, the applicant stated that the staff is correct that these components are subject to a sheltered internal environment. Duke's aging management review conservatively evaluated environments such as tanks and piping that are open to atmosphere as a ventilation environment. Although the tanks and piping are open to sheltered environments, they would not experience significant air exchange and thus higher humidity and condensation could be present. The ventilation environment aging effect details account for the potential condensation, whereas the sheltered environment aging effect details do not. Loss of material and cracking due to alternate wetting and drying that concentrates contaminants are two aging effects considered plausible in a ventilation environment, but are not considered in sheltered environments. Loss of material due to selective leaching is another aging effect considered plausible in a ventilation environment, but is not considered in sheltered environments. Therefore, for conservatism, Duke chose to evaluate these component configurations using the ventilation environment aging management review details. The designation in the LRA table reflects this decision.

In electronic correspondence dated May 2, 2002, the staff requested additional justification for the applicant's statement in Table 3.3-14 that carbon steel external components are subject to a sheltered environment while the internal environment is ventilation. The sheltered environment is subject to the aging effect of loss of material and is managed by the "Inspection Program for Civil Engineering Structures and Components." This appeared to the staff to conflict with Duke's RAI response, which states that loss of material in sheltered environments is not considered an aging effect. The staff requested that the applicant clarify or justify how an "uncontrolled" sheltered environment is less conservative than a "controlled" ventilation environment and causes no aging effects or revise the aging effects and AMPs listed in Table 3.3-13 to be consistent with other sheltered environments listed in the tables. The staff further noted that its fundamental concern was that, for the diesel engine exhaust systems (which include no equipment [coolers or dryers] for controlling air quality), the internal environments are "sheltered," not "ventilation," and that the aging effects associated with the sheltered environment must be addressed for these internal surfaces.

In electronic correspondence dated May 10, 2002 (ML021440236), the applicant replied as follows:

> For Duke, a sheltered environment is an external environment for components inside a structure that may or may not be maintained by a ventilation system but are protected from the natural elements. Components in a sheltered environment could be wet from condensation or leakage that could promote aggressive corrosion, that left unmanaged, could result in a loss of the component intended function(s) during the period of extended operation. As such, the Inspection Program for Civil Engineering Structures and Components is credited to manage the aging effects on the external surfaces of components located in a sheltered environment.
>
> For components with an internal air environment open to the sheltered environment or yard environment (as is the case with the diesel exhaust), Duke classified the environment as a ventilation environment. Duke conservatively chose the ventilation environment because more aging mechanisms leading to aging effects are plausible and must be considered than in a sheltered environment. In our initial response to RAI 3.3-5, Duke tried to show that aging effects from some mechanisms are not plausible in a sheltered environment but could occur in a ventilation environment. Duke was providing examples to support our conservative position which we believe does not say that loss of material in a sheltered environment is not an aging effect.
>
> Duke evaluated the internal environment of the exhaust systems as a ventilation environment. The diesels operate periodically for short periods of time for testing but are primarily in standby. The internal environment is characterized as a warm, dry environment free from leaks and condensation. This environment does not preclude loss of material but does not promote the aggressive corrosion that left unmanaged would result in a loss of the component intended function(s) of the exhaust system components. Therefore, no aging effects requiring management during the period of extended operation were identified.

By letter dated July 9, 2002, the staff received this information from the applicant in official correspondence. The applicant confirmed that the internal environment is warm, dry, and free from leaks and condensation. Since this environment does not promote the aggressive corrosion that would result in a loss of the component intended function(s) of the exhaust system components, this issue is resolved.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.14-1, additional information pertaining to Table 3.3-14, "Aging Management Review for Diesel Generator Air Intake and Exhaust System." This table does not list an internal environment of hot diesel engine exhaust gasses containing moisture and particulates. By letter dated January 23, 2002, the staff requested the applicant identify where in the LRA the AMR results are for steel components exposed to a hot diesel exhaust environment that have the potential for experiencing loss of material from general, pitting and crevice corrosion, or to provide a justification for excluding this environment and aging effects from Table 3.3-14 and an AMR.

In its response dated March 15, 2002, the applicant stated that Table 3.3-14 of the LRA presents the results of the aging management review for the diesel generator intake and exhaust system components. The diesel generators are normally in standby and are operated periodically for a short period of time for surveillance testing. During diesel operation, the exhaust portion of this system will be exposed to hot gasses containing moisture and particulates. Exposure duration of the exhaust components to the hot gasses containing moisture and particulates is insignificant when compared to the exposure time of these components to the cool, ventilation environment. As a result, the internal environment of hot gasses containing moisture and particulates was not considered in the aging management review to identify the aging effects requiring management. Therefore, Table 3.3-14 listed ventilation as the internal environment and did not include hot gases as an internal environment. The staff finds that applicant's response provides a reasonable explanation of why the environment is ventilation rather than exhaust. Since the standby D/G only test run periodically, the staff agrees that the subject exhaust components will not be exposed to the hot gasses containing moisture and particulates.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.14-2, additional information pertaining to information provided in Table 3.5-2, "Aging Management Review Results for Other Structures." This table indicates that rubber materials in sheltered environments are subject to the aging effects of cracking and change in material properties. The staff requested that the applicant explain why the rubber and composite rubber materials of Table 3.3-14, that are also in sheltered environments, are not subject to the aging effects of cracking and change in material properties.

In its response dated March 15, 2002, the applicant stated that elastomers could crack due to exposure to ultraviolet radiation, ozone, elevated temperature, or irradiation. Elastomers could experience a change in material properties due to exposure to elevated temperatures or irradiation. Damaging levels of radiation, temperature, and ozone are not present throughout the entire sheltered environment. As a result, elastomer location must be considered to identify the aging effects requiring management. The elastomers in Table 3.3-14 of the LRA are located in the diesel room. Radiation, temperature, and ozone are below the levels to be a concern in this location. Therefore, no aging effects requiring management were identified for these elastomers. Since the applicant indicated that these elastomers are located in an area where radiation and temperature is not significant enough to cause degradation, the staff finds the response acceptable.

The staff finds that the applicant's responses to RAIs 3.3.14-1 and 3.3.14-2 clarify and satisfactorily resolve these items. The aging effects that result from contact of diesel generator air intake and exhaust system SSCs to the environments described in Section 2.3.3.11 and Table 3.3-14, pages 3.3-118 through 3.3-120, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.11.2.2 Aging Management Programs

Section 2.3.3.11 and Table 3.3-14, pages 3.3-118 through 3.3-120, of the LRA states that the following aging management program is credited for managing the aging effects in the diesel generator air intake and exhaust system:

- Inspection Program for Civil Engineering Structures and Components

The Inspection Program for Civil Engineering Structures and Components is credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-14, the staff concludes that the above identified AMP will effectively manage the aging effects of the diesel generator air intake and exhaust system and that there is reasonable assurance that the intended functions of the diesel generator air intake and exhaust system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.11.3 Conclusions

The staff reviewed the information in Section 2.3.3.11 and Table 3.3-14 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generator air intake and exhaust system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.12 Diesel Generator Cooling Water System

3.3.12.1 Technical Information in the Application

The diesel generator cooling water system is essentially the same and performs the same function for McGuire and Catawba. The diesel generator cooling water system maintains the temperature of each emergency diesel generator engine and support systems within a required operating range. The McGuire UFSAR Section 9.5.5, Diesel Generator Cooling Water System, provides additional information concerning the McGuire diesel generator cooling water system. The Catawba UFSAR Section 9.5.5, Diesel Generator Engine Cooling Water, provides additional information concerning the Catawba diesel generator engine cooling water system.

3.3.12.1.1 Aging Effects

Components of the diesel generator cooling water system are described in Section 2.3.3.12 of the submittal as being within the scope of license renewal, and subject to an AMR. Tables 3.3-15 and 3.3-16, pages 3.3-121 through 3.3-130, of the LRA lists individual components of the system including the annubars, tanks, heat exchanger, intercoolers, pumps, heaters, flow orifices, piping, tubing, lube oil coolers, stand pipes, and valve bodies. Stainless steel components are identified as being subject to cracking and loss of material from exposure to the internal environment of treated water. Exposure of stainless steel to sheltered environment has no aging effects. Carbon steel components are subject to the aging effect of loss of material from internal surfaces from treated water, raw water, and ventilation environments. Internal surfaces to carbon steel components are also subject to cracking from exposure to treated water environments. Carbon steel is also subject to an aging effect of loss of material to external surfaces from exposure to sheltered environments. Exposure of internal surfaces of carbon steel components to a ventilation environment has no aging effect. Copper components are exposed to an internal and external environment of ventilation with no aging effects identified. Copper components exposed to an internal and external environments of raw water and treated water are subject to the aging effects fouling and loss of material. Cast iron components exposed to treated water and sheltered environments are subject to loss of material from internal and external surfaces. Brass components exposed to an internal and external environments of raw water and treated water are subject to the aging effects fouling and loss of material. Internal surfaces of aluminum components exposed to treated water are subject to cracking and loss of material. Aluminum and brass exposed to oil or sheltered environments demonstrate no aging effects.

3.3.12.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the diesel generator cooling water system:

- Galvanic Susceptibility Program
- Heat Exchanger Preventive Maintenance Activities - Diesel Generator Engine Cooling Water
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Performance Test Activity - Diesel Engine Cooling Water Exchanger
- Service Water Piping Corrosion Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of diesel generator cooling water system will be adequately managed by these aging management programs during the period of extended operation.

3.3.12.2 Staff Evaluation

The applicant described its AMR of the diesel generator cooling water system for license renewal in two separate sections of its LRA: Section 2.3.3.12 and Tables 3.3-15 and 3.3-16, pages 3.3-121 through 3.3-130. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the diesel generator cooling water system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.12.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.12 and Tables 3.3-15 and 3.3-16, pages 3.3-121 through 3.3-130, of the LRA. During its review the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3-3, additional information pertaining to Tables 3.3-16, 3.3-20, and 3.3-21. According to Table 3.3-16, the Catawba D/G governor lube oil coolers (tubes) are subject to an internal/external environment of treated water/oil. Similarly, Tables 3.3-20 and 3.3-21 indicate that the D/G engine lube oil coolers (tubes, tube sheets and/or shells) are listed as subject to an internal/external environment of treated water/oil. The staff requested the applicant to identify where in the LRA the aging effect of loss of material for these components in oil systems subject to water contamination was addressed.

In its response dated March 15, 2002, the applicant stated that all of the lube oil cooler components cited in the first paragraph of RAI 3.3-3 are components of closed oil recirculation systems. Uncontaminated lube oil does not cause aging, and closed oil recirculation systems are assumed to be initially free of contaminants such as water. Further, in the Duke aging management review, component failures were not postulated as a means to establish the relevant conditions required for aging to occur. Therefore, in oil coolers, tube failures that could introduce water into a lube oil environment are not assumed. The staff agrees that uncontaminated oil will not cause any aging effect to the components and that the applicant is not required to assume a failure that can cause an aging effect. The staff finds that the applicant's response to RAI 3.3-3 clarifies and satisfactorily resolves this item.

The aging effects that result from contact of the diesel generator cooling water system SSCs to the environments described in Section 2.3.3.12 and Tables 3.3-15 and 3.3-16, pages 3.3-121 through 3.3-130, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.12.2.2 Aging Management Programs

Section 2.3.3.12 and Tables 3.3-15 and 3.3-16, pages 3.3-121 through 3.3-130, of the LRA states that the following aging management programs are credited for managing the aging effects in the diesel generator cooling water system.

- Galvanic Susceptibility Program
- Heat Exchanger Preventive Maintenance Activities - Diesel Generator Engine Cooling Water
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Performance Test Activity - Diesel Engine Cooling Water Exchanger
- Service Water Piping Corrosion Program

The Galvanic Susceptibility Inspection Program, Chemistry Control Program, Inspection Program for Civil Engineering Structures and Components, and Service Water Piping Corrosion Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and, with the exception of open item 3.0.3.15.2-1 pertaining to the service water piping corrosion program, found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. The staff's evaluation of the Heat Exchanger Performance Test Activity - Diesel Generator Engine Cooling Water Program and Preventive Maintenance Activities - Diesel Engine Cooling Water Exchanger Program follows.

<u>Heat Exchanger Performance Testing Activities - Diesel Generator Engine Cooling Water</u>

The applicant described its performance testing activities of the diesel generator engine cooling water heat exchangers in Section B.3.17.3.1 of Appendix B of the LRA. The staff reviewed the LRA to determine whether the applicant had demonstrated that this program will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

The applicant stated that the purpose of the performance testing activities of the diesel generator engine cooling water heat exchangers is to manage fouling of copper and brass heat exchanger tubes that are exposed to raw water. This is considered by the applicant to be a performance monitoring program that monitors specific component parameters to detect the presence of fouling, which can affect the heat transfer function of the component.

The staff's evaluation of the performance testing activities of the diesel generator engine cooling water heat exchangers program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope] The scope of the performance testing activities of the diesel generator engine cooling water heat exchangers includes the tubes of the following:

- diesel generator engine cooling water heat exchangers (McGuire only)
- diesel generator engine jacket water coolers (Catawba only)

The applicant noted that these components serve the same function at both plants, but have different names because of the different diesel suppliers.

The staff finds the scope of the programs to be acceptable because it covers components important to the system function and will allow identification of fouling which can affect the heat transfer function of the component.

[Preventive or Mitigative Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff agrees with the applicant because the purpose of the program is to detect and assess the extent of material loss, not to prevent such loss.

[Parameters Monitored or Inspected] The applicant stated that at McGuire, the performance testing activities - diesel generator engine cooling water heat exchangers involve monitoring of flow capacity by performance of a differential pressure test to provide an indication of fouling. At Catawba, the performance testing activities involve monitoring of the heat transfer capability by performance of a heat capacity test to provide an indication of fouling. The staff finds the parameters monitored to be acceptable, because they are typical of industry practice for determining fouling in heat exchanger tubes. The different methods used at the two plants are both acceptable methods of testing.

[Detection of Aging Effects] The applicant stated that in accordance with the information provided under monitoring and trending, the performance testing activities will detect fouling prior to loss of the component intended function(s). The staff finds the applicant's approach acceptable, because it is based on standard industry approved methods.

[Monitoring and Trending] The applicant stated that due to different system design features at McGuire and Catawba, different parameters are monitored to manage fouling of the heat exchanger tubes. At McGuire, the performance testing activities involves measurement of the differential pressure across the raw water side of the heat exchangers every six months. Differential pressure provides a direct indication of fouling of the heat exchanger tubes. At Catawba, a heat capacity test computes a tube side fouling factor using tube and shell side inlet and outlet temperatures and flow rates every six months. Heat capacity provides a direct indication of fouling of the heat exchanger tubes. The staff finds that the monitoring and trending methods used, although different at the two plants, rely on standard engineering methods which are equally capable of detecting fouling in the heat exchanger tubes. Because the monitoring methods will allow the applicant to detect and correct fouling before it results in loss of cooling function, the staff finds the monitoring activities to be acceptable.

[Acceptance Criteria] The applicant stated that at McGuire, the acceptance criterion for the performance testing activities is the established differential pressure value that ensures fouling does not prevent the heat exchangers from performing their design basis function. At Catawba, the applicant stated that acceptance criteria for the performance testing activities are established by engineering calculation and the comparison of the test results to the acceptance criteria ensures fouling does not prevent the heat exchangers from performing their design basis function. The staff finds the acceptance criterion for both plants to be acceptable, because the testing methods will detect degradation of the heat exchangers and will allow corrective action to be taken before fouling can result in loss of the design function.

[Operating Experience] The applicant stated that operating experience associated with the performance testing activities has demonstrated that the fouling factor and the tube side differential pressure provide adequate indications to predict when corrective action is required for heat transfer surface fouling. Corrective action, in the form of tube cleaning, for example, is performed before the heat transfer function of the heat exchanger tubes is degraded below its required capacity. The applicant stated that with relatively low in-service duration and good valve isolation, the diesel generator engine cooling water heat exchangers usually do not accumulate large amounts of fouling materials on internal tubing surfaces.

The applicant’s measurement and trending of the heat exchanger tubes using NDT provides an accurate indication of material condition. The frequency of monitoring permits the results to be trended in order to determine when corrective action is required. Based on the review of the applicant’s operating experience, the staff finds that the inspections and monitoring activities have demonstrated that the techniques being used allow for the tending of the loss of material and any required corrective actions to be performed before the loss of component intended function.

FSAR Supplement: In Appendix A-1, Section 18.2.13 and Appendix A-2, Section 18.2.12, the applicant has provided proposed FSAR Supplements for McGuire and Catawba, respectively. The staff reviewed this information and found it to be consistent with the information provided in Appendix B, Section B.3.17 and is therefore acceptable.

In conclusion, the staff has reviewed the information in Section B.3.17.3.1 of the LRA. On the basis of this review and the above evaluation, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the performance testing activities - diesel generator engine cooling water heat exchangers program will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Heat Exchanger Preventive Maintenance Activities - Diesel Generator Engine Cooling Water

The applicant described its preventive maintenance activities of the diesel generator engine cooling water heat exchangers in Section B.3.17.3.2 of Appendix B of the LRA. The staff reviewed the LRA to determine whether the applicant had demonstrated that this program will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

The applicant stated that the purpose of the preventive maintenance activities of the diesel generator engine cooling water heat exchangers is to manage the loss of material for parts of the diesel generator engine cooling water heat exchangers exposed to raw water. The preventive maintenance activities of the diesel generator engine cooling water heat exchangers is a condition monitoring program that monitors specific component parameters to detect the presence and assess the extent of material loss that can affect the pressure boundary function. The applicant credited the program with managing the subject aging effects for brass and copper heat exchanger tubes.

The staff's evaluation of the preventive maintenance testing activities of the diesel generator engine cooling water heat exchangers program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope] The applicant defined the scope of the heat exchanger preventive maintenance activities -- diesel generator engine cooling water as the tubes of the following:

- diesel generator engine cooling water heat exchangers (Mcguire only)
- diesel generator engine jacket water coolers (Catawba only)

The applicant noted that these components serve the same function at both plants, but have different names because of the different diesel suppliers.

The staff noted that the applicant relies on other aging management programs, such as the chemistry control program, to manage the aging effects of the heat exchanger shell, channel head, and tubesheets. The staff finds the scope to be acceptable because it includes those components important to assuring that the pressure boundary is maintained.

[Preventive or Mitigative Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff agrees with the applicant because the purpose of the program is to detect and assess the extent of material loss, not to prevent such loss.

[Parameters Monitored or Inspected] The heat exchanger preventive maintenance activities - diesel generator engine cooling water program consists of the inspection of the heat exchanger tubes that will provide an indication of loss of material. The staff finds the applicant's approach acceptable because the inspections will identify areas affected by corrosion or erosion and provide an opportunity to take corrective actions prior to loss of pressure boundary integrity.

[Detection of Aging Effects] The applicant stated that the heat exchanger preventive maintenance activities - diesel generator engine cooling water inspections will detect loss of material due to crevice, general, pitting, and microbiologically influenced corrosion and loss of material due to particle erosion prior to loss of the component intended function. The staff finds this acceptable because the inspection methods used have been demonstrated to be capable of identifying the corrosion and erosion effects that are relied on as indications of tube wall thinning.

[Monitoring and Trending] The applicant stated that the heat exchanger preventive maintenance activities - diesel generator engine cooling water program performs eddy current testing on the heat exchanger tubes to measure wall thickness in order to detect areas with loss of material. Trending is performed in order to predict a heat exchanger replacement or repair schedule. The applicant stated that NDT (eddy current) is performed on approximately 50 percent of the tubes of each heat exchanger at least once every two years, based on operating experience and engineering evaluation of the test data. The staff finds this acceptable because eddy current testing is a standard method used in the industry for this type of inspection. The staff agrees that by trending the test data and use of operating experience, the applicant will be able to schedule replacement or repair prior to loss of component function.

[Acceptance Criteria] The applicant stated that the acceptance criterion for the heat exchanger preventive maintenance activities - diesel generator engine cooling water program is no unacceptable loss of material of the tubes that could result in a loss of the component intended function as determined by engineering evaluation. The staff does not consider this an adequate acceptance criterion for the heat preventive maintenance activities AMP. In addressing the acceptance criteria, the staff requests the applicant to specify parameters with quantitative limits (e.g., percent of flow blockage or percent of loss of heat transfer). Therefore, this issue is characterized as open item 3.0.3.9.1.2-1(f).

[Operating Experience] The applicant stated that the operating experience associated with the heat exchanger preventive maintenance activities - diesel generator engine cooling water program has demonstrated that the eddy current testing provides adequate information in regards to the presence of wall loss in the heat exchanger tubes to predict when corrective action is required. Corrective action in the form of tube plugging, for example, is performed before the loss of the component's intended function.

Due to operating experience at Catawba, the applicant stated that the frequency of eddy current testing had been increased at both sites. During 1992-93, the Catawba 2 diesel generator engine cooling water heat exchangers experienced circumferential cracking of the tubes. Complete tube severance occurred on several tubes. The investigation by the applicant revealed that the Catawba 2 heat exchangers were set up on a weekly nuclear service water system flush schedule (whereas Catawba 1 heat exchangers were not). Circumferential cracks were determined to be linked to the thermal shock received during the nuclear service water flushes. The applicant discontinued the flushes and a special eddy current test probe was employed to determine the extent of circumferential cracking defects. Repairs were in the form of plugging and re-tubing.

The applicant’s operating experience has demonstrated that the diesel generator engine cooling water heat exchanger activities program is an effective program for managing the effects of aging. The program with its proven monitoring techniques, acceptance criteria, and corrective actions accurately predicts aging effects due to erosion and corrosion. Therefore, the staff finds that the applicant is effectively applying the operating experience at their sites to improve the preventive maintenance activities related to the diesel generator engine cooling water system.

FSAR Supplement: In Appendix A-1, Section 18.2.13 and Appendix A-2, Section 18.2.12, the applicant provided proposed FSAR Supplements for McGuire and Catawba, respectively. The staff reviewed this information and found it to be in agreement with the information in Appendix B and is therefore, acceptable.

During its review of the information in Section 2.3.3.12; Tables 3.3-15 and 3.3-16, pages 3.3-121 through 3.3-130; and Section B.3.17 of the LRA, the staff identified the need for additional information pertaining to this AMP. By letter dated January 23, 2002, the staff requested, in RAI 3.3.15-1, additional information pertaining to Table 3.3-15, "Aging Management Review Results for Diesel Generator Cooling Water System (McGuire Nuclear Station)." This table indicates that the aging effect of loss of material in a raw water environment to the diesel generator cooling water heat exchangers is managed by the "Galvanic Susceptibility Inspection" aging management program (AMP). The scope of this program, as defined in Appendix B, Section B.3.16, does not include the diesel generator cooling water heat exchangers. The staff requested confirmation that the AMP, "Galvanic Susceptibility Inspection," manages the aging effects to the diesel generator cooling water heat exchangers.

In its response dated March 15, 2002, the applicant stated that the diesel generator cooling water heat exchangers reject heat from the diesel generator cooling water system to the nuclear service water system. The channel heads and tube sheets are constructed of carbon steel that are electrolytically coupled to stainless steel and copper, respectively, in the presence of raw water supplied by the nuclear service water system. The scope of the Galvanic Susceptibility Inspection as described in Appendix B of the LRA includes the galvanic couples of the nuclear service water system, which would include the galvanic couples in the portion of the diesel generator cooling water heat exchangers exposed to raw water in the nuclear service water system. Since the scope of the Galvanic Susceptibility Inspection includes the galvanic couples in the portion of the diesel generator cooling water heat exchangers, the aging effect will be managed by the program. The staff finds that the applicant’s response clarifies and satisfactorily resolves this item.

The staff has reviewed the information in Section B.3.17.3.2 of the LRA. On the basis of this review and the above evaluation, with the exception of open item 3.0.3.9.1.2-1(f) pertaining to acceptance criteria for the heat exchanger preventive maintenance activities, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the preventive maintenance activities - diesel generator engine cooling water heat exchangers program will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on its review of Tables 3.3-15 and 3.3-16 and Appendix B of the LRA, with the exception of open item 3.0.3.9.1.2-1(f) pertaining to acceptance criteria for the heat exchanger preventive maintenance activities and open item 3.0.3.15.2-1 pertaining to the service water piping corrosion program, the staff concludes that the above identified AMPs will effectively manage the aging effects of the diesel generator cooling water system and that there is reasonable assurance that the intended functions of the diesel generator air intake and exhaust system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.12.3 Conclusions

The staff reviewed the information in Section 2.3.3.12 and Tables 3.3-15 and 3.3-16, of the LRA. On the basis of its review, with the exception of open items 3.0.3.9.1.2-1(f) and 3.0.3.15.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generator cooling water system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.13 Diesel Generator Crankcase Vacuum System

3.3.13.1 Technical Information in the Application

The diesel generator crankcase vacuum system is essentially the same and performs the same function for McGuire and Catawba. The diesel generator crankcase vacuum system purges the diesel engine crankcase to reduce the concentration of combustible gases. The McGuire UFSAR Section 9.5.9, Diesel Generator Crankcase Vacuum System, provides additional information concerning the McGuire diesel generator crankcase vacuum system.

3.3.13.1.1 Aging Effects

Components of the diesel generator crankcase vacuum system are described in Section 2.3.3.13 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-17, pages 3.3-131 through 3.3-133, of the LRA lists individual components of the system including the blowers, oil separators, orifices, piping, tubing, and valve bodies. Stainless steel components exposed to sheltered and ventilation environments demonstrate no aging effects. Internal surfaces of carbon steel components exposed to ventilation environment have no aging effects. External surfaces of carbon steel exposed to yard and sheltered environments demonstrate the aging effect of loss of material. Brass and copper exposed to ventilation and sheltered environments show no aging effects.

3.3.13.1.2 Aging Management Programs

The following AMP is utilized to manage aging effects to the diesel generator crankcase vacuum system:

- Inspection Program for Civil Engineering Structures and Components

A description of the aging management program is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the diesel generator crankcase vacuum system will be adequately managed by the aging management program during the period of extended operation.

3.3.13.2 Staff Evaluation

The applicant described its AMR of the diesel generator crankcase vacuum system for license renewal in two separate sections of its LRA: Section 2.3.3.13 and Table 3.3-17, pages 3.3-131 through 3.3-133. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the diesel generator crankcase vacuum system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.13.2.1 Aging Effects

The aging effects that result from contact of the diesel generator crankcase vacuum system SSCs to the environments described in Section 2.3.3.13 and Table 3.3-17, pages 3.3-131 through 3.3-133, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.13.2.2 Aging Management Programs

Section 2.3.3.13 and Table 3.3-17, pages 3.3-131 through 3.3-133, of the LRA states that the following aging management program is credited for managing the aging effects in the diesel generator crankcase vacuum system.

- Inspection Program for Civil Engineering Structures and Components

The Inspection Program for Civil Engineering Structures and Components is credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff’s evaluation of this AMP is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-17, the staff concludes that the above identified AMP will effectively manage the aging effects of the diesel generator crankcase vacuum system and that there is reasonable assurance that the intended functions of the diesel generator crankcase vacuum system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.13.3 Conclusions

The staff reviewed the information in Section 2.3.3.13 and Table 3.3-17, pages 3.3-131 through 3.3-133, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generator crankcase vacuum system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.14 Diesel Generator Fuel Oil System

3.3.14.1 Technical Information in the Application

The McGuire diesel generator fuel oil system is relied upon to maintain two trains of fuel oil storage and supply for the emergency diesel generators for a period of operation of no less than five days. The McGuire UFSAR Section 9.5.4, Diesel Generator Fuel Oil System, provides additional information concerning the McGuire diesel generator fuel oil system.

The Catawba diesel generator engine fuel oil system is relied upon to maintain two trains of fuel oil storage and supply for the emergency diesel generators for a period of operation of no less than seven days. The Catawba UFSAR Section 9.5.4, Diesel Generator Engine Fuel Oil System, provides additional information concerning the Catawba diesel generator engine fuel oil system.

3.3.14.1.1 Aging Effects

Components of the diesel generator fuel oil system are described in Section 2.3.3.14 of the submittal as being within the scope of license renewal, and subject to AMR. Tables 3.3-18 and 3.3-19, pages 3.3-134 through 3.3-141, of the LRA lists individual components of the system including pump casing, tanks, filters, flame arrestors flow meters, orifices, strainers, pipes, tubing, and valve bodies. Stainless steel components exposed to an internal environment of oil are subject to the aging effect of loss of material. Exposure of external surfaces of stainless steel to an underground environment causes the aging effects of cracking and loss of material. Exposure of stainless steel to ventilation, yard, and sheltered environments has no aging effect. Exposure of carbon steel to internal and external environments of oil, underground, and sheltered environments is subject to the aging effect of loss of material. Exposure of internal surfaces of carbon steel components exposed to a ventilation environment has no aging effect. Cast iron components exposed to oil (internal) and sheltered (external) environments are subject to the aging effect of loss of material.

3.3.14.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the diesel generator fuel oil system:

- Inspection Program for Civil Engineering Structures and Components
- Chemistry Control Program
- Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the diesel generator fuel oil system will be adequately managed by these aging management programs during the period of extended operation.

3.3.14.2 Staff Evaluation

The applicant described its AMR of the diesel generator fuel oil system for license renewal in two separate sections of its LRA: Section 2.3.3.14 and Tables 3.3-18 and 3.3-19, pages 3.3-134 through 3.3-141. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the diesel generator fuel oil system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.14.2.1 Aging Effects

The aging effects that result from contact of the diesel generator fuel oil system SSCs to the environments described in Section 2.3.3.14 and Tables 3.3-18 and 3.3-19, pages 3.3-134 through 3.3-141, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.14.2.2 Aging Management Programs

Section 2.3.3.14 and Tables 3.3-18 and 3.3-19, pages 3.3-134 through 3.3-141, of the LRA states that the following aging management programs are credited for managing the aging effects in the diesel generator fuel oil system.

- Inspection Program for Civil Engineering Structures and Components
- Chemistry Control Program
- Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection

The Chemistry Control Program, Inspection Program for Civil Engineering Structures and Components, and Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and, with the exception of open item 3.0.3.13.2-1 on the Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection program (see Section 3.0.3.13.2 of this SER), found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Tables 3.3-18 and 3.3-19, with the exception of open item 3.0.3.13.2-1, the staff concludes that the above identified AMPs will effectively manage the aging effects of the diesel generator fuel oil system and that there is reasonable assurance that the intended functions of the diesel generator fuel oil system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.14.3 Conclusions

The staff reviewed the information in Section 2.3.3.14 and Tables 3.3-18 and 3.3-19, pages 3.3-134 through 3.3-141, of the LRA. On the basis of its review, with the exception of open item 3.0.3.13.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generator fuel oil system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.15 Diesel Generator Lube Oil System

3.3.15.1 Technical Information in the Application

The McGuire and Catawba diesel generator lube oil systems are essentially the same and perform the same function. The diesel generator lube oil system supplies lubricating oil to the diesel engine and its bearings, crankshaft, thrust faces, and other friction surfaces during both the standby mode and operation mode of the diesel generator. The McGuire UFSAR Section 9.5.7, Diesel Generator Lubricating Oil System, provides additional information concerning the McGuire diesel generator lube oil system. The Catawba UFSAR Section 9.5.7, Diesel Generator Engine Lube Oil System, provides additional information concerning the Catawba diesel generator engine lube oil system.

3.3.15.1.1 Aging Effects

Components of the diesel generator lube oil system are described in Section 2.3.3.15 of the submittal as being within the scope of license renewal, and subject to AMR. Tables 3.3-20 and 3.3-21, pages 3.3-142 through 3.3-148, of the LRA lists individual components of the system including pump casing, oil coolers, tanks, flexible hoses, heaters, strainers, oil filters, oil heaters, pipes, tubing, and valve bodies. Stainless steel components exposed to internal or external oil and sheltered environments are not subject to any aging effects. Carbon steel components exposed to an internal environment of treated water are subject to the aging effects of cracking and loss of material. Internal surfaces of carbon steel exposed to oil have no aging effect. Exposure of carbon steel to a sheltered external environment causes loss of material. Cast iron components exposed to the internal environment oil are not subject to any aging effects, while external surfaces exposed to sheltered environments are subject to loss of material. Copper alloy, copper nickel, and brass components exposed to a treated water internal environment are subject to cracking and loss of material. Exposure of copper alloy and brass to an external environment of oil has no aging effect.

3.3.15.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the diesel generator lube oil system:

- Inspection Program for Civil Engineering Structures and Components
- Chemistry Control Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the diesel generator lube oil system will be adequately managed by these aging management programs during the period of extended operation.

3.3.15.2 Staff Evaluation

The applicant described its AMR of the diesel generator lube oil system for license renewal in two separate sections of its LRA: Section 2.3.3.15 and Tables 3.3-20 and 3.3-21, pages 3.3-142 through 3.3-148. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the diesel generator lube oil system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.15.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.15 and Tables 3.3-20 and 3.3-21, pages 3.3-142 through 3.3-148, of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3-3, additional information pertaining to Tables 3.3-16, 3.3-20 and 3.3-21. Table 3.3-16 (pages 3.3-126 to 3.3-130) indicates that the Catawba D/G governor lube oil coolers (tubes) are subject to an internal/external environment of treated water/oil. According to Tables 3.3-16, 3.3-20 and 3.3-21, the D/G engine lube oil coolers (tubes, tube sheets and/or shells) are listed as subject to an internal/external environment of treated water/oil. The staff requested that the applicant identify where in the LRA the aging effect of loss of material was addressed.

In its response dated March 15, 2002, the applicant stated that all of the lube oil cooler components cited in the first paragraph of RAI 3.3-3 are components of closed oil recirculation systems. Uncontaminated lube oil does not cause aging, and closed oil recirculation systems are assumed to be initially free of contaminants such as water. Further, in the Duke aging management review, component failures were not postulated as a means to establish the relevant conditions required for aging to occur. Therefore, in oil coolers, tube failures that could introduce water into a lube oil environment are not assumed. The staff agrees that uncontaminated oil will not cause any aging effect to the components and that the applicant is not required to assume a failure that can cause an aging effect. The staff finds that the applicant's response to RAI 3.3-3 clarifies and satisfactorily resolves this item.

In its April 15, 2002, response to RAI 2.3.3.15-4, the applicant stated that the diesel generator lube oil heater pump casings were within the scope of license renewal (see Section 2.3.3.15.2 of this SER). The following AMR results for these components were provided in the applicant's response:

Component Type	**Component Function**	**Material**	**Internal Environment** **External Environment**	**Aging Effects**	**Aging Management Programs and Activity**
D/G Lube Oil Heater Pump Casings	PB	CS	Oil	None Identified	None Required
			Sheltered	Loss of Material	Inspection Program for Civil Engineering Structures and Components

The aging effects that result from contact of the diesel generator lube oil system SSCs to the environments described in the applicant's response to RAI 2.3.3.15-4, Section 2.3.3.15 and Tables 3.3-20 and 3.3-21, pages 3.3-142 through 3.3-148, of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.15.2.2 Aging Management Programs

Section 2.3.3.15 and Tables 3.3-20 and 3.3-21, pages 3.3-142 through 3.3-148, of the LRA states that the following aging management programs are credited for managing the aging effects in the diesel generator lube oil system.

- Inspection Program for Civil Engineering Structures and Components
- Chemistry Control Program

The Chemistry Control Program and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

The staff reviewed the information in Section 2.3.3.15 and Tables 3.3-20 and 3.3-21, pages 3.3-142 through 3.3-148, of the LRA. During its review, the staff determined that additional information was needed to complete its review.

By letter dated January 23, 2002, the staff requested, in RAI 3.3-3, additional information on Tables 3.3-20 and 3.3-21, "Aging Management Review Results for diesel generator lube oil system (McGuire Nuclear Station)." These tables indicate that the aging effect of cracking and loss of material in a lube oil environment is managed by the AMP, "Chemistry Control Program." The scope of this program as defined in Appendix B, Section B.3.6, only refers to fuel oil environments and not lube oil. The staff asked if the AMP, "Chemistry Control Program," manages the aging effects in lube oil environment.

In its response dated March 15, 2002, the applicant stated that all of the lube oil cooler components cited in the first paragraph of RAI 3.3-3 are components of closed oil recirculation systems. Uncontaminated lube oil does not cause aging, and closed oil recirculation systems are assumed to be initially free of contaminants such as water. Further, in the Duke aging management review, component failures were not postulated as a means to establish the relevant conditions required for aging to occur. Therefore, in oil coolers, tube failures that could introduce water into a lube oil environment are not assumed. The staff agrees that uncontaminated oil will not cause any aging effect to the components and that the applicant is not required to assume a failure that can cause an aging effect. The staff finds that the applicant's response to RAI 3.3-3 clarifies and satisfactorily resolves this item.

Based on its review of LRA Tables 3.3-20 and 3.3-21, the staff concludes that the above identified AMPs will effectively manage the aging effects of the diesel generator lube oil system and that there is reasonable assurance that the intended functions of the diesel generator lube oil system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.15.3 Conclusions

The staff reviewed the information in the applicant’s response to RAI 2.3.3.15-4; Sections 2.3.3.15 and B.3.6 of the LRA; and Tables 3.3-18, 3.3-19, 3.3-20 and 3.3-21 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generator lube oil system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.16 Diesel Generator Room Sump Pump System

3.3.16.1 Technical Information in the Application

The McGuire diesel generator room sump pump system removes leakage from equipment drains in the diesel building and protects the diesel generators from flooding due to a nuclear service water system pipe rupture in one of the diesel rooms acting simultaneously with a turbine building flood. The McGuire UFSAR Section 9.5.10, Diesel Generator Room Sump Pump System, provides additional information concerning the McGuire diesel generator room sump pump system.

The Catawba diesel generator room sump pump system removes normal leakage and drainage from various equipment in the diesel generator rooms. The Catawba UFSAR Section 9.5.9, Diesel Generator Room Sump Pump System, provides additional information concerning the Catawba diesel generator room sump pump system.

3.3.16.1.1 Aging Effects

Components of the diesel generator room sump pump system are described in Section 2.3.3.16 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-22, pages 3.3-149 through 3.3-150, of the LRA lists individual components of the system including pump casings, orifices, pipes, and valve bodies. Stainless steel and carbon steel components exposed to an internal raw water environment experience loss of material. Exposure of stainless steel to sheltered environments is not subject to any aging effects, while exposure of carbon steel to a sheltered or yard external environment demonstrates loss of material. Cast iron components (McGuire) are subject to the aging effect of loss of material when exposed to an internal environment of raw water and a sheltered external environment.

3.3.16.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the diesel generator room sump pump system:

- Inspection Program for Civil Engineering Structures and Components
- Selective Leaching Inspection (McGuire only)
- Galvanic Susceptibility Inspection

• Sump Pump System Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the diesel generator room sump pump system will be adequately managed by these aging management programs during the period of extended operation.

3.3.16.2 Staff Evaluation

The applicant described its AMR of the diesel generator room sump pump system for license renewal in two separate sections of its LRA: Section 2.3.3.16 and Table 3.3-22, pages 3.3-149 through 3.3-150. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the diesel generator room sump pump system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.16.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.16 and Table 3.3-22, pages 3.3-149 through 3.3-150, of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3.22-1 additional information pertaining to Table 3.3-22, "Aging Management Review Results for the Diesel Generator Room Sump Pump System." This table indicates that orifices provide the function "PB." Typically, orifices also provide the function listed in Note 1 as "TH." The applicant was asked to explain why orifices in the diesel generator room sump pump system do not provide the function "TH," or correct the component functions for orifices listed in Table 3.3-22.

In its response dated March 15, 2002, the applicant stated that the system intended function of the diesel generator room sump pump system is to remove the contents of the diesel generator room sump to prevent room flooding that could damage equipment. The orifice included in Table 3.3-22 is located in a normally isolated recirculation line that is only used for testing the diesel generator room sump pumps. Throttling is, therefore, not an intended function of the orifice for license renewal. Since the orifice is only used for test run and not intended as “TH” function for normal operation, the staff finds the applicant’s response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.22-2, additional information pertaining to Table 3.3-22, "Aging Management Review Results for the Diesel Generator Room Sump Pump System." This table has a "Note (3)”, which implies that portions of the diesel generator room sump pump system may be subject to alternate wetting and drying; however, this note is not used in the table. The applicant was requested to clarify if note (3) is applicable to Table 3.3-22. If so, the applicant should explain how this environment and associated aging effects are managed in the LRA.

In its response dated March 15, 2002, the applicant stated that "Note 3," which implies some portions of the diesel generator room sump pump system are exposed to an alternate wetting and drying environment, is not applicable to Table 3.3-22 of the LRA. No components in the diesel generator room sump pump system within the scope of license renewal are exposed to an alternate wetting and drying environment, which may concentrate contaminants. The staff finds that the applicant's response clarifies and satisfactorily resolves this item since the components are not subject to an alternate wetting and drying environment and the aging effect is not applicable.

The aging effects that result from contact of the diesel generator room sump pump system SSCs to the environments described in Section 2.3.3.16 and Table 3.3-22, pages 3.3-149 through 3.3-150, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.16.2.2 Aging Management Programs

Section 2.3.3.16 and Table 3.3-22, pages 3.3-149 through 3.3-150, of the LRA states that the following aging management programs are credited for managing the aging effects in the diesel generator room sump pump system.

- Inspection Program for Civil Engineering Structures and Components
- Selective Leaching Inspection (McGuire only)
- Galvanic Susceptibility Inspection
- Sump Pump System Inspection

The Galvanic Susceptibility Inspection Program, Inspection Program for Civil Engineering Structures and Components, Selective Leaching Inspection (McGuire only), and Sump Pump System Inspection Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-22, the staff concludes that the above identified AMPs will effectively manage the aging effects of the diesel generator sump pump system and that there is reasonable assurance that the intended functions of the diesel generator sump pump system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.16.3 Conclusions

The staff reviewed the information in Section 2.3.3.16 and Table 3.3-22 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generator room sump pump system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.17 Diesel Generator Starting Air System

3.3.17.1 Technical Information in the Application

The McGuire and Catawba diesel generator starting air systems are essentially the same and performs the same function. The diesel generator starting air system provides fast start capability for the emergency diesel engine by using compressed air to roll the engine until it starts. The diesel generator starting air system also supplies air to the diesel controls to operate and shutdown the engine. The McGuire UFSAR Section 9.5.6, Diesel Generator Starting Air System, provides additional information concerning the McGuire diesel generator starting air system. The Catawba UFSAR Section 9.5.6, Diesel Generator Engine Starting Air System, provides additional information concerning the Catawba diesel generator engine starting air system.

3.3.17.1.1 Aging Effects

Components of the diesel generator starting air system are described in Section 2.3.3.17 of the submittal as being within the scope of license renewal, and subject to AMR. Tables 3.3-23 and 3.3-24, pages 3.3-151 through 3.3-157, of the LRA lists individual components of the system including air filters, tanks, coolers, flow meters, moisture separators, orifices, silencers, y-strainers, expansion joints, pipes, tubing, and valve bodies. Exposure of stainless steel to a sheltered external environment has no aging effect. Exposure of external surfaces of carbon steel to sheltered environments demonstrates loss of material. Stainless steel and carbon steel exposed to an internal environment of dry air has no aging effect. Exposure of stainless steel and carbon steel to moist air environments has no aging effect. Monel 400 components exposed to an internal environment of raw water are subject to loss of material, while the same components exposed to an external environment of moist air has no aging effect.

3.3.17.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the diesel generator starting air system:

- Inspection Program for Civil Engineering Structures and Components
- Service Water Piping Corrosion Program (Catawba only)
- Heat Exchanger Preventive Maintenance Activities - Diesel Generator Engine Starting Air (Catawba only)

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the diesel generator starting air system will be adequately managed by these aging management programs during the period of extended operation.

3.3.17.2 Staff Evaluation

The applicant described its AMR of the diesel generator starting air system for license renewal in two separate sections of its LRA: Section 2.3.3.17 and Tables 3.3-23 and 3.3-24, pages 3.3-151 through 3.3-157. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the diesel generator starting air system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.17.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.17 and Tables 3.3-23 and 3.3-24, pages 3.3-151 through 3.3-157, of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3.24-1, additional information pertaining to Table 3.3-24, "Aging Management Review Results for the Diesel Generator Starting Air System - Catawba." This table identifies only a PB function for the D/G engine starting air aftercooler tubes. The applicant was requested to explain why the heat transfer (HT) function, which ensures the system and/or component operating temperatures are maintained, is not considered in the AMR, or correct the component functions for D/G engine starting air aftercooler tubes listed in Table 3.3-24.

In its response dated March 15, 2002, the applicant stated that the diesel generator starting air aftercooler is not required to transfer heat for the safety-related diesel to perform its function. The diesel generator starting air aftercooler and associated piping and components are non-safety-related because they are not required to function for the diesel to start and operate. The aftercooler is within the scope of license renewal because both sides of the cooler have a pressure boundary function. The pressure boundary of the cooling water side of the aftercooler is safety-related because it forms a pressure boundary of the safety-related nuclear service water system and is therefore within scope. The pressure boundary of the air side of the aftercooler is non-safety-related but is seismically designed and designated Class F. Therefore, the pressure boundary of the air side of the aftercooler meets the criteria of §54.4(a)(2) and is within scope. The Class F design was applied to the system to minimize the effort to regain the diesel in a post seismic situation. Since the aftercooler is not required to transfer heat during the start-up of the diesel generator, the staff agrees that "HT" function is not a required function.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.24-2, additional information pertaining to Table 3.3-24, "Aging Management Review Results for the Diesel Generator Starting Air System - Catawba." This table indicates that the D/G engine starting air aftercooler tubes are made of stainless steel and subject to loss of material from exposure to a raw water internal environment. Typically, the aging effect, fouling, is also associated with raw water environments. The applicant was requested to identify where in the LRA the AMR results are for the aging effects fouling to these components, or to provide a justification for excluding this aging effect from Table 3.3-24 and an AMR.

In its response dated March 15, 2002, the applicant stated that fouling can cause a loss of heat transfer function but does not affect the pressure boundary function of the diesel generator starting air system aftercooler tubes. As discussed in the response to RAI 3.3.24-1 above, heat transfer is not a component intended function of the aftercoolers. The staff agrees with the applicant that fouling is not an applicable aging effect since the system does not perform a heat transfer function.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.24-4, additional information pertaining to Table 3.3-24, "Aging Management Review Results for the Diesel Generator Starting Air System - Catawba." This table identifies several components where carbon steel is exposed to an air (moist) environment with no aging effects or aging management program required. Loss of material from general, pitting, and crevice corrosion is an applicable aging effect for carbon steel materials in air environments containing moisture. General corrosion results from chemical or electrochemical reaction between the material and the air environment when both oxygen and moisture are present. The applicant was requested to identify where in the LRA the AMR results are for these aging effects, or to provide a justification for excluding this aging effect from Table 3.3-24 and an AMR.

In its response dated March 15, 2002, the applicant stated that Table 3.3-24 of the application presents the results of the aging management review for the diesel generator starting air system. Loss of material due to crevice, general, galvanic, and pitting corrosion were evaluated for the diesel generator starting air system carbon steel components exposed to moist air. Duke determined that crevice, galvanic, and pitting corrosion were not a concern for the period of extended operation. Crevice and pitting corrosion are a concern in air environments where surfaces are alternately wetted and dried which could concentrate contaminants. Galvanic corrosion occurs in an air environment when dissimilar materials are wet. These conditions do not exist in the moist air portion of the diesel generator starting air system.

Duke considered loss of material due to general corrosion of the carbon steel components and determined that it was not an aging effect requiring management during the period of extended operation. Absent other influences such as wetting and drying, general corrosion of carbon steel occurs at a slow rate. The entire diesel generator starting air system is located in the same room with the diesel engines and is normally in standby. The system draws air from the diesel room to charge the tanks. The diesels are warmed to 125°F and that results in a room temperature of around 100°F. The air environment inside the system before the dryers can be characterized as stagnant warm air of a low humidity. This environment would not promote aggressive general corrosion such that the component intended function would be lost if left unmanaged for the period of extended operation. Therefore, loss of material due to general corrosion of the carbon steel components exposed to moist air is not an aging effect requiring management during the period of extended operation. Since the applicant stated that the air environment inside the system before the dryers can be characterized as stagnant warm air of a low humidity, the staff agrees that localized and general corrosion are very unlikely to occur.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.24-5, additional information pertaining to Table 3.3-24, "Aging Management Review Results for the Diesel Generator Starting Air System - Catawba." This table identifies environments air (dry) and air (moist) as potential environments for the diesel generator starting air system. Descriptions for these environments are not provided in Section 3.3.1 "Aging Management Review Results Tables," of the LRA. The applicant was requested to identify where in the LRA these environments are defined, or provide additional information in Section 3.3.1 of the LRA

In its response dated March 15, 2002, the applicant stated that the two environments, air (moist) and air (dry), were provided in Table 3.3-24 to show that the air environment was not the same throughout the diesel generator starting air system. Both of these air environment variations are bounded by the "Air-Gas" environment definition in Section 3.3.1 of the application. The diesel generator starting air system takes air from the diesel room. The air is filtered, compressed, dried and stored in tanks to be used to start the diesels. The air (moist) environment is the environment prior to the air dryers. The air (dry) environment is the environment after the air dryers.

In electronic correspondence dated May 2, 2002, the staff indicated that the applicant's response addressed the original question dealing with defining the air (moist) and air (dry) environmental conditions. However, the initial RAI attempted to determine why no aging effects were identified for carbon steel in the air (moist) environment. Aging mechanisms and rates can vary depending on the moisture content in these environments. The staff requested that the applicant provide additional detail to address aging effect under the air (moist) environment.

In electronic correspondence dated May 10, 2002 (ML021440236), the applicant replied that Duke believes that characterizing the environment as moist air is misleading. The applicant noted its initial response, in which it stated that the diesel generator starting air system takes air from the diesel room. Since the diesels are heated, the moist air of the diesel rooms is in excess of 100°F and has a low relative humidity. The diesel generator starting air system filters, compresses and further dries this air for storage in the system tanks for later use. The diesel room air does not preclude loss of material but does not promote the aggressive corrosion that left unmanaged could result in a loss of the intended function(s) of the components. Therefore, no aging effects requiring management during the period of extended operation were identified.

By letter dated July 9, 2002, the staff received this explanation in official correspondence. The applicant confirmed that the diesel starting air system components are exposed to an environment that with low relative humidity, and the diesel generator starting air system filters, compresses and further dries this air for storage in the system tanks for later use. The staff finds that, since the diesel room air does not promote the aggressive corrosion that could result in a loss of the intended function(s) of the system components, this issue is resolved.

In its April 15, 2002, response to RAI 2.3.3.17-2, the applicant determined that the diesel generator starting air distributor filter was within the scope of license renewal (see Section 2.3.3.17.2 of this SER). The following AMR results for this component were provided in the applicant's response:

Component Type	Component Function	Material	Internal Environment External Environment	Aging Effect	Aging Management Programs and Activities
Starting Air Distributor Filter	PB	CS	Air (Dry) Sheltered	None Identified None Identified	None Required None Required

The staff finds that the applicant's AMR results are not consistent with the other carbon steel components in a sheltered environment, which the applicant indicated (in the LRA) is subject to the aging effect of loss of material. Since the applicant has not identified this aging effect for the diesel generator starting air distributor filter, and credited an AMP to manage this aging effect, the staff finds that the aging effect (none) listed is not appropriate for the combination of material and environment identified. Therefore, this issue is characterized as open item 3.3.17.2.1-1.

The staff finds that the applicant's responses to RAIs 3.3.24-1, 3.3.24-2, 3.3.24-4, and 3.3.24-5 clarify and satisfactorily resolve these items. The aging effects that result from contact of the diesel generator starting air system SSCs to the environments described in Section 2.3.3.17 and Tables 3.3-23 and 3.3-24, pages 3.3-151 through 3.3-157, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, with the exception of open item 3.3.17.2.1-1, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.17.2.2 Aging Management Programs

Section 2.3.3.17 and Tables 3.3-23 and 3.3-24, pages 3.3-151 through 3.3-157, of the LRA states that the following aging management programs are credited for managing the aging effects in the diesel generator starting air system.

- Inspection Program for Civil Engineering Structures and Components
- Service Water Piping Corrosion Program (Catawba only)
- Heat Exchanger Preventive Maintenance Activities - Diesel Generator Engine Starting Air (Catawba only)

The Inspection Program for Civil Engineering Structures and Components, and Service Water Piping Corrosion Program (Catawba only) are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and, with the exception of open item 3.0.3.15.2-1 pertaining to the service water piping corrosion program, found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. The staff's evaluation of the Heat Exchanger Preventive Maintenance Activities - Diesel Generator Engine Starting Air (Catawba only) Program follows.

<u>Heat Exchanger Preventive Maintenance Activities - Diesel Generator Engine Starting Air Program (Catawba only)</u>

The applicant described its preventive maintenance activities of the diesel generator engine starting air heat exchangers in Section B.3.17.5 of Appendix B of the LRA. The staff reviewed the LRA to determine whether the applicant had demonstrated that this program will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3). This program is applicable only to Catawba. Because of the different materials and environments of the McGuire diesel generator starting air system components, the aging effects are not the same as those that are found at Catawba. The only aging effect at McGuire is loss of material for subject piping and tanks and is managed by the inspection program for civil engineering structures and components.

Section B.3.17.5 of Appendix B of the LRA provides a description of the applicant's preventive maintenance activities for the diesel generator engine starting air system. The stated purpose of the heat exchanger preventive maintenance activities - diesel generator engine starting air is to manage loss of material for parts of the diesel generator engine starting air aftercoolers exposed to raw water. The applicant described the heat exchanger preventive maintenance activities - diesel generator engine starting air as a condition monitoring program that monitors specific component parameters to detect the presence and assess the extent of material loss that can affect the pressure boundary function. The applicant credits the program with managing loss of material for carbon steel and stainless steel materials.

The staff's evaluation of heat exchanger preventive maintenance activities-diesel generator engine starting air focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope] As described in the LRA, the scope of the heat exchanger preventive maintenance activities - diesel generator engine starting air includes the tubes and channel heads of the diesel generator engine starting air aftercooler. The staff finds the scope of this activity to be acceptable because it includes those components important to assuring that the pressure boundary is maintained.

[Preventive or Mitigative Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff agrees with the applicant because the purpose of the program is to detect and assess the extent of material loss, not to prevent such loss.

[Parameters Monitored or Inspected] In conducting the heat exchanger preventive maintenance activities - diesel generator engine starting air program, the applicant inspects the aftercooler tube and channel head surfaces for loss of material. The staff finds this approach to be acceptable because it will allow the applicant to identify material loss and take corrective action prior to loss of component function.

[Detection of Aging Effects] The applicant stated that based on information provided under the Monitoring and Trending section, the heat exchanger preventive maintenance activities - diesel generator engine starting air program will detect loss of material due to crevice, galvanic, general, pitting, and microbiologically influenced corrosion and loss of material due to particle erosion prior to loss of the component intended function. The staff's review found this acceptable, because the applicant performs visual inspections of the channel head surface and using a borescope (for tubes), which is a standard industry method. The staff agrees that the program is capable of detecting and correcting aging degradation before loss of component function.

[Monitoring and Trending] As described in the application, the heat exchanger preventive maintenance activities - diesel generator engine starting air manages loss of material of the tubes and channel heads by means of two visual inspections. Loss of material of the tube internal surfaces is managed by an annual inspection. This inspection uses a borescope to visually inspect the tubes.

The applicant stated that loss of material of the channel heads is managed by an annual visual inspection of the protective coatings to assure the integrity of the underlying base metal. The channel heads of the diesel generator engine starting air aftercoolers are coated with a high solids epoxy. The coating inspection specifically identifies rust blooms, which indicate a coating defect and corrosion of the base metal.

The applicant takes no actions as part of this activity to trend inspection results. The staff did not identify the need for trending actions. The staff finds that the annual inspections are capable of identifying loss of material or other aging effects prior to loss of component function.

[Acceptance Criteria] The applicant stated that the acceptance criteria for the heat exchanger preventive maintenance activities - diesel generator engine starting air is no unacceptable loss of material of the tubes and channel heads that could result in a loss of the component intended function(s) as determined by engineering evaluation. The staff does not consider this an adequate acceptance criterion for the heat preventive maintenance activities AMP. In addressing the acceptance criteria, the staff requests the applicant to specify parameters with quantitative limits (e.g., percent of flow blockage or percent of loss of heat transfer). Therefore, this issue is characterized as open item 3.0.3.9.1.2-1(g).

[Operating Experience] The applicant stated that its operating experience associated with the heat exchanger preventive maintenance activities - diesel generator engine starting air program has demonstrated that visual inspection of the aftercooler tubes and channel heads provide adequate information in regards to wall loss present in the aftercooler components to predict when corrective action is required. Corrective action in the form of tube plugging or coating repair, for example, is performed before the loss of the component intended function. Results of the inspection have led the applicant to replace the aftercooler tubes and the coating of the tube sheets and channel heads. The applicant stated that original equipment Monel tubes in the diesel generator engine starting air aftercoolers were retubed with stainless steel in 1996-1997. Monel tubes had shown signs of serious pitting damage. According to the applicant, the replacement stainless steel tubes are also showing signs of pitting as well, but to a lesser degree than the Monel, and are being evaluated for retubing.

The applicant’s operating experience has demonstrated that the preventive maintenance activities - diesel generator engine starting air heat exchanger program is an effective program for managing the effects of aging. The program with its proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls, accurately predicts aging effects due to corrosion and erosion.

FSAR Supplement: In Appendix A-2, Section 18.2.12, the applicant has provided proposed FSAR Supplements for Catawba. This program will be applied only at Catawba. The staff reviewed this information and found it to be consistent with the information provided in Appendix B, Section B.3.17 and is acceptable.

During its review of information in Section 2.3.3.17; Tables 3.3-23 and 3.3-24, pages 3.3-151 through 3.3-157; and Section B.3.17 of the LRA, the staff identified the need for additional information pertaining to this AMP. By letter dated January 23, 2002, the staff requested, in RAI 3.3.24-3, additional information pertaining to Table 3.3-24, "Aging Management Review Results for the Diesel Generator Starting Air System - Catawba." This table identifies the Heat Exchanger Preventive Maintenance Program for diesel generator starting air as the aging management program to manage the aging effect of loss of material in a raw water environment for the D/G engine starting air aftercooler tubes and channel head, but not the tube sheet which is Monel 400 material. Section 18.2.12.5 of the FSAR Supplement, "Diesel Generating Starting Air," credits this program for managing aging of carbon steel, stainless steel and Monel materials. The applicant was asked if the AMP, "Heat Exchanger Preventive Maintenance Program for Diesel Generator Starting Air," manages the aging effect loss of

Monel 400 material to the D/G engine starting air aftercooler tube sheet exposed to a raw water environment. If not, the applicant was requested to explain the intent of statements made in Section 18.2.12.5 of the FSAR Supplement, "Diesel Generating Starting Air," which indicates that this program is credited for managing aging of carbon steel, stainless steel and Monel materials.

In its response dated March 15, 2002, the applicant stated that Table 3.3-24 and Appendix B (B.3.17.5) are correct. The Heat Exchanger Preventive Maintenance Program for Diesel Generator Starting Air is not credited with managing loss of material of the Monel 400 tubesheets of the diesel generator starting air aftercooler. The Service Water Piping Corrosion Program is credited with managing loss of material of the Monel 400 tubesheets of the diesel generator starting air aftercooler, as indicated in Table 3.3-24. Section 18.2.12.5 of the Catawba FSAR Supplement is in error and will be revised. The staff has reviewed the Service Water Piping Corrosion Program and agrees that it will appropriately manage loss of material of the Monel 400 tubesheets. The staff finds that the applicant’s response clarifies and satisfactorily resolves this item.

The staff has reviewed the information in Section B.3.17.5 of the LRA. On the basis of this review and the above evaluation, with the exception of open item 3.0.3.9.1.2-1(g) pertaining to acceptance criteria for the heat exchanger preventive maintenance activities, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the preventive maintenance activities - diesel generator engine starting air heat exchangers program will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on its review of Tables 3.3-23 and 3.3-24 and Appendix B of the LRA, with the exception of open item 3.0.3.9.1.2-1(g) pertaining to acceptance criteria for the heat exchanger preventive maintenance activities, open item 3.3.17.2.1-1 pertaining to loss of material for the carbon steel starting air distributor filter in a sheltered environment, and open item 3.0.3.15.2-1 pertaining to the service water piping corrosion program, the staff concludes that the above identified AMPs will effectively manage the aging effects of the diesel generator starting air system and that there is reasonable assurance that the intended functions of the diesel generator starting air system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.17.3 Conclusions

The staff reviewed the information in Section 2.3.3.17; Tables 3.3-23 and 3.3-24; and Section B.3.17 of the LRA. On the basis of its review, with the exception of open items 3.0.3.9.1.2-1(g), 3.3.17.2.1-1, and 3.0.3.15.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with diesel generator starting air system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.18 Drinking Water System

3.3.18.1 Technical Information in the Application

No portion of the McGuire drinking water system is within the scope of license renewal. Only the Duke Class F portions of the drinking water system are in scope at Catawba. McGuire has no Class F components in the drinking water system.

The Catawba drinking water system is a municipal water system consisting of a water tower, pumps, and chemical treatment equipment providing chlorinated drinking water to the plant. The drinking water system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this system are within the scope of license renewal per §54.4(a)(2).

3.3.18.1.1 Aging Effects

Components of the drinking water system are described in Section 2.3.3.18 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-25, page 3.3-158, of the LRA lists individual components of the system including pipes and valve bodies. Stainless steel components exposed to an internal treated water environment are subject to the aging effects of cracking and loss of material. Exposure of the same stainless steel components to a sheltered external environment has no aging effect.

3.3.18.1.2 Aging Management Programs

The following AMP is utilized to manage aging effects to the drinking water system:

- Treated Water Systems Stainless Steel Inspection

A description of the aging management program is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the drinking water system will be adequately managed by the aging management program during the period of extended operation.

3.3.18.2 Staff Evaluation

The applicant described its AMR of the drinking water system for license renewal in two separate sections of its LRA: Section 2.3.3.18 and Table 3.3-25, page 3.3-158. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the drinking water system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.18.2.1 Aging Effects

The aging effects that result from contact of the drinking water system SSCs to the environments described in Section 2.3.3.18 and Table 3.3-25, page 3.3-158, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.18.2.2 Aging Management Programs

Section 2.3.3.18 and Table 3.3-25, page 3.3-158, of the LRA states that the following aging management program is credited for managing the aging effects in the drinking water system.

- Treated Water Systems Stainless Steel Inspection

The Treated Water Systems Stainless Steel Inspection Program is credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-25, the staff concludes that the above identified AMP will effectively manage the aging effects of the drinking water system and that there is reasonable assurance that the intended functions of the drinking water system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.18.3 Conclusions

The staff reviewed the information in Section 2.3.3.18 and Table 3.3-25, page 3.3-158, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the drinking water system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.19 Fire Protection System

3.3.19.1 Technical Information in the Application

The McGuire and Catawba interior/exterior fire protection systems are essentially the same and perform the same function. The interior/exterior fire protection systems provide fire suppression to protect the capability to shut down the reactor and maintain it in a safe shutdown condition and to minimize radioactive releases to the environment in the event of a fire. In addition, the system provides water to the condenser circulating water pump and low level intake pump bearings. The McGuire UFSAR Section 9.5.1, Fire Protection System, provides additional information concerning the McGuire interior/exterior fire protection system. The Catawba UFSAR Section 9.5.1, Fire Protection System provides additional information concerning the Catawba interior/exterior fire protection system.

3.3.19.1.1 Aging Effects

Components of the fire protection systems are described in Section 2.3.3.19 of the submittal as being within the scope of license renewal, and subject to AMR. Tables 3.3-26 and 3.3-27, pages 3.3-159 through 3.3-191, of the LRA lists individual components of the system including cylinders, tanks, hose racks, flexible hoses, pressure switches, rupture discs, spray nozzles, sprinklers, orifices, dampeners, pump casings, standpipes, pipes, and valve bodies. Stainless steel components exposed to raw water environments are subject to loss of material. Stainless steel components exposed to ventilation, reactor building, sheltered, and yard demonstrate no aging effects. Internal or external surfaces of carbon steel exposed to raw water, sheltered, yard, underground, or reactor building environments demonstrate the aging effect of loss of material. Exposure of carbon steel to ventilation or gas environments has no aging effect. Cast iron components exposed to internal or external raw water, underground, yard, or sheltered environments are subject to loss of material. Cast iron exposed to a ventilation environment is not subject to any aging effects. Galvanized steel exposed to raw water, yard, underground, or sheltered internal or external environments is subject to loss of material. External surfaces of galvanized steel exposed to ventilation or embedded environments demonstrate no aging effects. External surfaces of alloy steel exposed to sheltered environments are subject to loss of material. Exposure of alloy steel to a gas environment has no aging effect. Brass components exposed to external sheltered, yard, or reactor building environments demonstrate loss of material, while the same components exposed to internal ventilation or gas environments show no aging effects. Brass components exposed to raw water environments are subject to fouling and loss of material. Copper, malleable iron, and ductile iron components exposed to sheltered environments are subject to loss of material. Exposure of copper, malleable iron, and ductile iron components to ventilation environments demonstrate no aging effects. Bronze components subject to internal environments of raw water are subject to fouling and loss of material. Exposure of bronze components to ventilation environments is not subject to any aging effects. Exposure of external surfaces of bronze to a sheltered, yard, or reactor building environment causes loss of material.

3.3.19.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the interior/exterior fire protection systems:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Galvanic Susceptibility Inspection
- Service Water Piping Corrosion Program
- Fire Protection Program
- Selective Leaching Inspection
- Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the interior/exterior fire protection systems will be adequately managed by these aging management programs during the period of extended operation.

3.3.19.2 Staff Evaluation

The applicant described its AMR of the fire protection systems for license renewal in two separate sections of its LRA: Section 2.3.3.19 and Tables 3.3-26 and 3.3-27, pages 3.3-159 through 3.3-191. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the fire protection system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.19.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.19 and Tables 3.3-26 and 3.3-27, pages 3.3-159 through 3.3-191, of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3.26-1, additional information pertaining to Table 3.3-26, "Aging Management Review Results for the Fire Protection System - McGuire." This table indicates that sprinklers have a spray flow function. The last sprinkler component in Table 3.3-26 (page 3.3-164) is missing the SP (spray flow) designation. The applicant was requested to correct the table, or justify why the spray flow function is not applicable to these sprinkler entries.

In its response dated March 15, 2002, the applicant stated that the last sprinkler entry in Table 3.3-26 (page 3.3-164) should have contained the SP designation. The programs listed for this sprinkler will serve to manage the SP function consistent with other similar entries in Table 3.3-26. Since the applicant has indicated that the SP function is applicable, the staff finds this response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.26-2, additional information pertaining information in Table 3.3-26, "Aging Management Review Results for the Fire Protection System - McGuire." A statement in the LRA that the fire protection program is credited with managing the aging effect fouling in raw water environments for carbon steel, brass and bronze valves. Carbon steel, brass and bronze valve body components are identified in the exterior fire protection section of Table 3.3-26, but fouling has not been identified as an aging effect. The applicant was requested to identify where in the LRA the AMR results are for the aging effect of fouling for these components, or to provide a justification for excluding this aging effect from Table 3.3-26 and an AMR.

In its response dated March 15, 2002, the applicant stated that fouling is an applicable aging effect only for a specific set of components in the fire protection systems where a fouled condition could prevent the supply of fire suppression water. As described in Section B.3.12.2, Mechanical Fire Protection Component Tests and Inspections, of the LRA, fouling is managed for specific distribution components of the fire protection systems (sprinklers, hose station valves, and hydrant valves). Managing the impact of fouling on these components ensures that the system is capable of performing its function of supplying fire suppression water through the distribution components. In the interior fire protection system at McGuire, fouling is an applicable aging effect for sprinklers and brass and bronze hose station valves exposed to raw water. In the exterior fire protection system at McGuire, fouling is not an applicable aging effect for the cast iron hydrant valves exposed to raw water because no cast iron hydrant valves are relied upon for fire suppression distribution. This latter point differs from Catawba, where hydrant valves are relied upon for fire suppression distribution and for which fouling is an applicable aging effect. Since there are no cast iron hydrant valves relied upon for fire suppression distribution at McGuire, the staff finds this response acceptable.

The applicant also stated that, upon further review of Table 3.3-26 and consistent with this discussion, an error exists in the McGuire exterior fire protection portion of the table. Fouling should not be an applicable aging effect for the cast iron valve bodies in the yard and exposed to raw water. The Table 3.3-26 entry for the cast iron valve bodies in the yard and exposed to raw water was revised to reflect this. The staff believes that this revision clarifies the item.

By letter dated January 23, 2002, the staff requested, in RAI-3.3.26-3,additional information pertaining to Table 3.3-27, "Aging Management Review Results for the Fire Protection System - Catawba." This table indicates that “Note (4)” is applicable in several locations in the table where components are subject to the aging effect fouling. There is no definition for “Note (4)” at the end of Table 3.3-27. The applicant was requested to clarify if “Note (4)” is applicable to Table 3.3-27 and, if so, to define it.

In its response dated March 15, 2002, the applicant stated that “Note 4" applies to Table 3.3-27. The note was inadvertently omitted from the table notes. “Note 4" should read "Fire Hose Rack Valves Only." Upon further review of the Table 3.3-27, an additional notation error was discovered. The fouling entry on page 3.3-189 should contain a “Note 5" instead of “Note 4.” “Note 5" should read "Fire Hydrant Valves Only." Since the applicant corrected the error, the staff finds that the applicant's response clarifies and satisfactorily resolves this item.

The aging effects that result from contact of the fire protection system SSCs to the environments described in Section 2.3.3.19 and Tables 3.3-26 and 3.3-27, pages 3.3-159 through 3.3-191, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.19.2.2 Aging Management Programs

Section 2.3.3.19 and Tables 3.3-26 and 3.3-27, pages 3.3-159 through 3.3-191, of the LRA states that the following aging management programs are credited for managing the aging effects in the fire protection system.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Galvanic Susceptibility Inspection
- Service Water Piping Corrosion Program
- Fire Protection Program - Mechanical Fire Protection Component Tests and Inspections
- Selective Leaching Inspection
- Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection

The Fluid Leak Management Program, Galvanic Susceptibility Inspection Program, Service Water Piping Corrosion Program, Inspection Program for Civil Engineering Structures and Components, Fire Protection Program, Selective Leaching Inspection Program and Liquid

Waste System Inspection Program, and Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and, with the exception of open item 3.0.3.13.2-1 pertaining to the Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection program and open item 3.0.3.15.2-1 pertaining to the Service Water Piping Corrosion program, found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. The staff's review of the Fire Protection Program - Mechanical Fire Protection Component Tests and Inspections follows:

<u>Mechanical Fire Protection Component Tests and Inspections</u>

The applicant described its tests and inspections of mechanical fire protection components in Section B.3.12.2 of the LRA. The applicant credits these activities with managing the potential aging of specific fire protection system components that are within the scope of license renewal. The staff reviewed Section B.3.12.2 of the LRA to determine whether the applicant has demonstrated that tests and inspections of mechanical fire protection components will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

Section B.3.12.2 of the LRA describes the Mechanical Fire Protection Component Tests and Inspections. The purpose of this program is to manage loss of material and fouling of specific components in the fire protection systems. The program manages loss of material in sprinklers that can affect the pressure boundary and spray functions of the sprinklers. The program also manages fouling of sprinklers, valves at hydrants, and valves at hose racks that can affect the component function. This program is a condition monitoring program that is credited with managing the subject aging effect for brass and bronze materials exposed to a raw water environment.

Operating experience has demonstrated that fouling is an aging effect requiring management for the fire protection systems at McGuire and Catawba. The systems use lake water as their water source. The stations have been working to manage fouling through the use of chemical treatment, testing, and inspections. For the purpose of license renewal, fouling is being applied to the distribution components (sprinklers, hose station valves, and hydrant valves) of the fire protection systems. Managing fouling of the distribution components ensures that the system is capable of performing its function of supplying fire suppression water through the distribution components.

The staff's evaluation of the program focused on how the program manages the aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective action program, while the administrative controls are governed by SLCs and implemented through plant procedures and the site work processes. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] The components within the scope of the program are the sprinklers and fire hydrant valves and hose rack valves of the interior and exterior fire protection systems. The staff finds the program scope adequate and acceptable.

[Parameters Monitored or Inspected] The program involves visual inspections to verify sprinkler condition, and flow is monitored during flow tests and flushes of the system to verify that there is no blockage of flow that will prevent system function. The staff finds that visual inspection will detect loss of material due to general, crevice, and pitting corrosion, as well as loss of seal or cracking due to embrittlement. Internal conditions are monitored through the use of leakage, flow, and pressure testing. Internal loss of material (due to general, crevice, and pitting corrosion; microbiologically influenced corrosion, and selective leaching) and blockage due to fouling can be detected by changes in flow or pressure, leakage, or evidence of excessive corrosion products during flushing of the system. The staff finds that the parameters monitored will permit timely detection of the aging effects and are, therefore, acceptable.

[Detection of Aging Effects] The applicant stated that detection of degradation on external surfaces is determined by visual examination. Surfaces of components and structures are examined for damage, deterioration, leakage, or other forms of corrosion. Section B.3.12.2 of the LRA states that functional testing and flushing of the system clears away internal scale, debris, and other foreign material that could lead to blockage/obstruction of the system. Flow and pressure tests verify system integrity. Visual examination of breached portions of the system also verifies unobstructed flow and integrity of the piping/components. In response to the staff's RAIs, the applicant stated that volumetric examinations will also be performed, as described below. The staff finds the detection of aging effects adequate and acceptable.

[Monitoring and Trending] The program manages loss of material and fouling through visual inspections and system flow tests and flushes.

Section B.3.12.2 of the LRA states that loss of material of sprinklers is detected through the use of visual inspections. Sprinklers are visually inspected at least once very 18 months in accordance with SLC 16.9.2. Additionally, a sample of sprinklers are either inspected or replaced at 50 years of operation.

By letter dated January 28, 2002, the staff requested (in RAI B.3.12.2-1) the applicant to describe the basis for the sampling process for testing and/or replacement of sprinklers after 50 years of operation. In its response dated March 15, 2002, the applicant indicated that the rationale for replacement or testing comes from NFPA 25 - 1998, Section 2-3.1.1, which states:

> Where sprinklers have been in service for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory acceptable to the authority having jurisdiction for field service testing.

The applicant indicated that samples will be selected based on the different environments (temperature, humidity, etc.) that the sprinklers were exposed to during their 50 year service life. The staff finds the response acceptable because it conforms to NFPA guidelines.

Section B.3.12.2 of the LRA states that fouling of hose station valves, hydrant valves, and sprinklers is managed by various flow tests and flushes performed on the systems. Distribution loops experience high-volume flow when hydrant valves are periodically opened. This is performed for the outside distribution loop every six months and is governed by SLC 16.9-1(a)(iii) for Catawba and Testing Requirement (TR) 16.9.1.3 for McGuire. Additional distribution loop flow tests are performed by procedure less frequently.

By letter dated January 28, 2002, the staff requested, in RAI B.3.12.2-2, the applicant to clarify the difference between SLC 16.9.1(a)(iii) at Catawba and TR 16.9.1.3 at McGuire, both of which govern the flow tests and flushes of hose station valves and sprinklers. In its response dated March 15, 2002, the applicant stated that the content of the two requirements is the same; they simply have different numbers. McGuire recently converted their SLC to a standardized Technical Specification format, while Catawba has not yet completed their conversion. Therefore, the surveillance numbering scheme is different between the plants' SLCs. The staff finds this clarification reasonable and acceptable.

Section B.3.12.2 of the LRA states that the integrity of hose station valves and hydrant valve is assured by supplying water to these components. Each hose station valve is opened at least once every three years per SLC 16.9-4. Hydrant valves are fully opened every six months. The hydrant tests are not governed by SLCs, but are performed by procedure.

Section B.3.12.2 of the LRA also states that the integrity of the sprinkler branch lines is assured by performing sprinkler system flow tests every 18 months. This procedure is performed by fully opening the inspector's test connection valve, which stimulates flow from the most hydraulically remote sprinkler head on each system. This test is governed by SLC TR 16.9-2(a)(iv)(1) at Catawba. The test is not governed by SLCs at McGuire, but is performed by procedure.

By letter dated January 28, 2002, the staff requested, in RAI B.3.12.2-3, the applicant to clarify why the sprinkler system flow testing for branch lines is governed by SLC TR 16.9-2(a)(iv) at Catawba, but is performed to satisfy a specific plant procedure at McGuire, and not governed by any SLC. In its response dated March 15, 2002, the applicant stated that during original licensing of McGuire, the sprinkler system flow test was not a required TS surveillance. During subsequent Catawba licensing, the surveillance was required to be placed in Technical Specifications. Since it was never in the original McGuire TS, it was not placed into the SLC during the TS conversion. Since the test is committed to as part of an AMP for license renewal, the sprinkler system flow test will be added to the McGuire FSAR Supplement. In its response to RAI B.3.12.2-3, the applicant indicated that the FSAR Supplement will be revised to include the sprinkler system flow test in accordance with their response to RAI B.3.2.12.2-4, which is discussed in the following paragraphs. The staff finds the clarification reasonable and acceptable because the integrity of the sprinkler branch lines will be ensured by performance of sprinkler system flow tests on a periodic basis.

Section B.3.12.2 of the LRA states that fouling of sprinkler branch lines that do not receive flow during this test will be managed by a sample disassembly inspection program. Since these lines do not receive flow, it is believed that they are less susceptible to fouling than the lines that receive flow during testing. To validate this belief, branch lines of a few representative sprinkler systems will be disassembled and the piping visually inspected. Subsequent inspections for the period of extended operation will be determined based on inspection results. If fouling is minimal, it is preferable to terminate the sample inspections because draining and filling activities introduces newly oxygenated water to those portions of the system which would have an adverse effect on corrosion and fouling of the lines.

By letter dated January 28, 2002, the staff requested, in RAI B 3.12.2-4, the applicant to explain the basis for the sample disassembly inspection program for managing the fouling of sprinkler branch lines. In its response dated March 15, 2002, the applicant stated that, in light of the view that the potential for general corrosion is accelerated by introducing new oxygen to the system when the system is opened, the applicant would revise this aspect of the program as described in Section B 3.12.2 of the LRA. Fouling of sprinkler branch lines that do not receive flow during flow tests was to be managed by disassembling the piping and visually inspecting the interior surfaces. The applicant proposes a combination of volumetric examination, such as radiography, and possibly sample disassembly to manage fouling of these branch lines. Some radiography of the fire protection piping has already been performed and provides excellent indication of corrosion product build-up in the lines. The applicant proposed using volumetric examination as a screening tool to determine if it is necessary to perform further intrusive inspections.

The branch line samples to be inspected by volumetric examination will be selected based on several factors. Samples will be chosen to try to obtain a representative sampling of the various environments (temperatures, flow condition, etc.) the sprinkler systems have been exposed to. Also, samples will be chosen based on pipe configurations that would lend themselves to worst case fouling (e.g., low points, multiple bends, etc.). The sample size will be determined based on obtaining a representative sample that would bound all of the selection parameters mentioned inspections on a particular branch line, then that branch line will be inspected as described in the Section B 3.12.2 of the application. The applicant indicated that the FSAR Supplements would be updated to reflect this use of volumetric examination to their AMP and to include the sprinkler system flow test in accordance with their response to RAI B.3.2.12.2-3 (previously discussed). The staff finds this response reasonable and acceptable because fouling of sprinkler branch lines that do not receive flow during periodic testing will be monitored by volumetric examination procedures.

By letter dated January 28, 2002, the staff requested, in RAI B.3.12.2-5, the applicant to indicated if its AMP conforms to the following staff position:

> The staff proposes to revise the fire protection program inspection criteria in NUREG-1801 for wall thinning of piping due to corrosion. Each time the system is opened, oxygen is introduced into the system, and this accelerates the potential for general corrosion. Therefore, the staff recommends that a non-intrusive means of measuring wall thickness, such as ultrasonic inspection, be used to detect this aging effect. The staff recommended action in this regard is that, in addition to an ultrasonic inspection of the fire protection piping before exceeding the current licensing term, the applicant perform ultrasonic inspections immediately after the 50-year service life sprinkler head testing, in accordance with NFPA 25, Section 2.3.3.1, and at 10-year intervals thereafter.

In its response dated March 15, 2002, the applicant provided the following:

> The “Service Water Piping Corrosion Program,” discussed in Section B 3.29 of the Application, manages wall thinning of piping due to corrosion of Fire Protection systems. The program uses ultrasonic inspection, a non-intrusive method to manage this effect. The nature of the program does not prescribe inspections at the specified times outlined by the staff position, but does ensure reinspection at an appropriate frequency based on the calculated corrosion rate. (See response to RAI B.3.29-2.) The program will likely impose inspections more frequently than that outlined in the staff’s position. The program is an existing program with adequate operating experience to provide reasonable assurance that it will manage the aging of fire protection systems as successfully as it has managed other raw water systems in the plant.

The staff finds the applicant’s response reasonable and acceptable, since it conforms with the proposed staff position on this issue.

By letter dated January 28, 2002, the staff requested, in RAI B 3.12.2-6, the applicant to describe the environmental and material conditions that exist on the interior surface of below-grade fire protection piping. The staff’s position is that if these conditions can be demonstrated to be similar to the conditions existing in the above-grade fire protection piping, then the inspections in the above-grade piping may be extrapolated to evaluate the interior conditions of the below-grade piping. If not, additional inspection activities may be needed to provide the reasonable assurance that the intended function of below-grade fire protection piping will be maintained consistent with the applicant’s licensing basis for the extended operation.

In its March 15, 2002, response, the applicant stated that the environmental conditions of the interior surface of the below-grade fire protection piping are exactly the same as that of the above-grade fire protection piping. The environment is stagnant lake water. The material conditions of the below-grade fire protection piping are different than that of the above-grade fire protection piping. The below-grade fire protection piping is cement-lined, providing it with an added feature to prevent the loss of material of the base metal due to corrosion. The cement lining also prevents internal buildup of turbucles that would contribute to the degradation of the pipe flow characteristics. In addition to the inspection activities, the testing features described in Section B 3.12.2 of the LRA perform testing on the below-grade as well as above-ground portion of the system to provide assurance that the entire system can perform its intended function. In addition, the applicant has performed intrusive visual inspections of the internal surfaces of the underground cement-lined piping during maintenance of modification work. The condition of the piping is excellent. The internal lining is intact, ensuring the integrity of the base metal. The staff finds the applicant’s response reasonable and acceptable.

The staff finds that the applicant’s methodology will provide effective monitoring and trending of the aging effects and is therefore, acceptable.

[Acceptance Criteria] Section B.3.12.2 of the LRA describes the acceptance criteria for the visual inspections of the sprinklers as, “an evaluation is performed for any cracks, corrosion, missing pipe hangers, obstructions to sprinkler spray pattern, and other piping abnormalities that are detected.” The acceptance criteria for system flushes and slow tests are, “water shall flow through the valve to the discharge point with no obvious signs of flow blockage.” The staff finds these acceptance criteria acceptable because the effects of aging will be detected and evaluated before loss of intended function would occur.

[Operating Experience] Section B.3.12.2 of the LRA describes the operating experience as follows:

McGuire Operating Experience
Fouling of the fire protection systems is being minimized by chemical treatment of the water. Additionally, system engineers monitor flow through the system headers and attempt to minimize header flow to reduce internal buildup of corrosion products. Flow tests have not detected unacceptable fouling in other areas where flows are limited. Over the past three years, sections of piping have been replaced due to pin-hole leaks or where fouling has been detected during permitted internal inspections. All corrective actions have been taken prior to loss of component intended function.

Catawba Operating Experience
Fouling of the fire protection systems is being minimized in recent years by chemical treatment of the water. Additionally, system engineers monitor flow through the system headers and attempt to minimize header flow to reduce internal buildup of corrosion products. Due to corrosion product buildup in the system, the Interior Fire Protection System auxiliary building header was cleaned in 1996. All corrective actions have been taken prior to loss of component intended function.

The staff finds that the operating experience at McGuire and Catawba indicates that aging of the fire protection system will be effectively managed during the period of extended operation.

FSAR Supplement: The staff has reviewed the UFSAR Section 18.2.8 of Appendix A to the LRA, and has confirmed that it contains the appropriate elements of the program.

In conclusion, the staff reviewed the information provided in Section B.3.12.2 of the LRA, the summary description provided in the FSAR Supplement, and the applicant's March 15, 2002, responses to the staff's RAIs. On the basis of its review, as discussed above, the staff finds that there is reasonable assurance that the Mechanical Fire Protection Component Tests and Inspections will adequately manage the aging effects such that the intended function(s) will be maintained in accordance with within the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on its review of Tables 3.3-26 and 3.3-27 and Appendix B of the LRA, with the exception of open item 3.0.3.13.2-1 pertaining to the Preventive maintenance Activities - Condenser Circulating Water System internal Coating Inspection program and open item 3.0.3.15.2-1 pertaining to the Service Water Piping Corrosion program, the staff concludes that the above identified AMPs will effectively manage the aging effects of the fire protection system and that there is reasonable assurance that the intended functions of the fire protection system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.19.3 Conclusions

The staff reviewed the information in Section 2.3.3.19; Tables 3.3-26 and 3.3-27; and Section B.3.12.2 of the LRA. On the basis of its review, with the exception of open items 3.0.3.13.2-1 and 3.0.3.15.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the fire protection system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.20 Fuel Handling Building Ventilation System

3.3.20.1 Technical Information in the Application

The fuel handling building ventilation system is essentially the same and performs the same function for McGuire and Catawba. The fuel handling building ventilation system maintains ventilation in the spent fuel pool buildings of Units 1 and 2 to permit personnel access. The exhaust portion of the fuel handling building ventilation system controls airborne radioactivity in the fuel pool area during normal operation, anticipated operational transients, and following postulated fuel handling accidents. The McGuire UFSAR Section 9.4.2, Auxiliary Building, provides additional information concerning the McGuire fuel handling building ventilation system. The Catawba UFSAR Section 9.4.2, Fuel Building Ventilation System, provides additional information concerning the Catawba fuel handling area ventilation system.

3.3.20.1.1 Aging Effects

Components of the fuel handling building ventilation system are described in Section 2.3.3.20 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-28, pages 3.3-192 through 3.3-193, of the LRA lists individual components of the system including air flow monitors, ductwork, filters, tubing, and valve bodies. Exposure of carbon steel, galvanized steel, copper, and brass to a sheltered external environment is subject to loss of material. These same components exposed to ventilation internal environments are not subject to any aging effects. Exposure of internal or external surfaces of stainless steel components to ventilation or sheltered environments has no aging effect.

3.3.20.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the fuel handling building ventilation system:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the fuel handling building ventilation system will be adequately managed by these aging management programs during the period of extended operation.

3.3.20.2 Staff Evaluation

The applicant described its AMR of the fuel handling building ventilation system for license renewal in two separate sections of its LRA: Section 2.3.3.20 and Table 3.3-28, pages 3.3-192 through 3.3-193. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the fuel handling building ventilation system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.20.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.20 and Tables 3.3-28, pages 3.3-192 through 3.3-193, of the LRA. The staff notes that RAI 3.3-1, pertaining to aging management of elastomer components associated with ventilation systems, applies to the fuel handling building ventilation system. However, the staff concluded that this RAI was resolved (see Section 3.3.39.3 of this SER). On the basis of its review, the staff finds that the aging effects that result from contact of the fuel handling building ventilation system SSCs to the environments described in Section 2.3.3.20 and Table 3.3-28, pages 3.3-192 through 3.3-193, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.20.2.2 Aging Management Programs

Section 2.3.3.20 and Table 3.3-28, pages 3.3-192 through 3.3-193, of the LRA states that the following aging management programs are credited for managing the aging effects in the fuel handling building ventilation system.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

The Fluid Leak Management Program and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-28, the staff concludes that the above identified AMPs will effectively manage the aging effects of the fuel handling ventilation system and that there is reasonable assurance that the intended functions of the fuel handling ventilation system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.20.3 Conclusions

The staff reviewed the information in Section 2.3.3.20 and Table 3.3-28 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with fuel handling building ventilation system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.21 Groundwater Drainage System

3.3.21.1 Technical Information in the Application

The groundwater drainage system is essentially the same and performs the same function for McGuire and Catawba. The groundwater drainage system prevents hydrostatic loads on the reactor and auxiliary building substructures. The groundwater drainage system maintains an acceptable groundwater level for the auxiliary building by transferring water out of the auxiliary building and mitigates the consequences of certain postulated flooding events. The McGuire

UFSAR Section 9.5.8, Groundwater Drainage System, provides additional information concerning the McGuire groundwater drainage system. The Catawba UFSAR Section 9.5.11, Groundwater Drainage System, provides additional information concerning the Catawba groundwater drainage system.

3.3.21.1.1 Aging Effects

Components of the groundwater drainage system are described in Section 2.3.3.21 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-29, pages 3.3-194 to 3.3-196, of the LRA lists individual components of the system including pump casings, pipe, orifices, tubing, and valve bodies. Stainless steel components are identified as being subject to the external environments of sheltered and yard with no aging effects identified. An internal environment of raw water causes the aging effect of loss of material in stainless steel components. Carbon steel components are subject to the aging effect of loss of material from internal and external surfaces from raw water and sheltered environments. Carbon steel components are identified as being subject to the external environment of embedded in concrete with no aging effects identified. Cast iron components are subject to the aging effect of loss of material on internal and external surfaces from raw water and sheltered environments.

3.3.21.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the groundwater drainage system:

- Inspection Program for Civil Engineering Structures and Components
- Selective Leaching Inspection (MNP only)
- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Sump Pump System Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the groundwater drainage system will be adequately managed by these aging management programs during the period of extended operation.

3.3.21.2 Staff Evaluation

The applicant described its AMR of the groundwater drainage system for license renewal in two separate sections of its LRA: Section 2.3.3.21 and Table 3.3-29, pages 3.3-194 to 196. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the groundwater drainage system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.21.2.1 Aging Effects

The aging effects that result from contact of the groundwater drainage system SSCs to the environments described in Section 2.3.3.21 and Table 3.3-29, pages 3.3-194 through 3.3-196, are consistent with industry experience for these combinations of materials and environments.

On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.21.2.2 Aging Management Programs

Section 2.3.3.21 and Table 3.3-29, pages 3.3-194 to 196, of the LRA states that the following aging management programs are credited for managing the aging effects in the groundwater drainage system.

- Inspection Program for Civil Engineering Structures and Components
- Selective Leaching Inspection (McGuire only)
- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Sump Pump System Inspection

The Fluid Leak Management Program, Galvanic Susceptibility Inspection Program, Sump Pump System Inspection Program, Inspection Program for Civil Engineering Structures and Components, and Selective Leaching Inspection Program (McGuire only) are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-29, the staff concludes that the above identified AMPs will effectively manage the aging effects of the groundwater drainage system and that there is reasonable assurance that the intended functions of the groundwater drainage system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.21.3 Conclusions

The staff reviewed the information in Section 2.3.3.21 and Table 3.3-29, pages 3.3-194 to 196, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the groundwater drainage system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.22 Hydrogen Bulk Storage System

3.3.22.1 Technical Information in the Application

The hydrogen bulk storage system is essentially the same and performs the same function for McGuire and Catawba. The hydrogen bulk storage system supplies hydrogen to the volume control tank (chemical and volume control system). The hydrogen bulk storage system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this system are within the scope of license renewal per §54.4(a)(2).

3.3.22.1.1 Aging Effects

Components of the hydrogen bulk storage system are described in Section 2.3.3.22 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-30, pages 3.3-197 to 198, of the LRA lists individual components of the system including pipe, tubing, and valve bodies. Stainless steel components are identified as being subject to the internal environment of gas and external environments of sheltered and yard with no aging effects identified. Carbon steel components are subject to the aging effect of loss of material from external surfaces exposed to sheltered environments. Carbon steel components are identified as being subject to the internal environment of gas with no aging effects identified. Brass components are subject to the aging effect of loss of material from external surfaces from exposure to sheltered environments. Internal surfaces of brass components exposed to gas are not subject to any aging effects. Copper components are subject to the aging effect of loss of material from external surfaces from exposure to sheltered environments. Internal surfaces of copper components exposed to gas are not subject to any aging effects.

3.3.22.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the hydrogen bulk storage system:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the hydrogen bulk storage system will be adequately managed by these aging management programs during the period of extended operation.

3.3.22.2 Staff Evaluation

The applicant described its AMR of the hydrogen bulk storage system for license renewal in two separate sections of its LRA: Section 2.3.3.22 and Table 3.3-30, pages 3.3-197 to 198. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the hydrogen bulk storage system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.22.2.1 Aging Effects

The aging effects that result from contact of the hydrogen bulk storage system SSCs to the environments described in Section 2.3.3.22 and Table 3.3-30, pages 3.3-197 through 3.3-198, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.22.2.2 Aging Management Programs

Section 2.3.3.22 and Table 3.3-30, pages 3.3-197 to 198, of the LRA states that the following aging management programs are credited for managing the aging effects in the hydrogen bulk storage system.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

The Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-30, the staff concludes that the above identified AMPs will effectively manage the aging effects of the hydrogen bulk storage system and that there is reasonable assurance that the intended functions of the hydrogen bulk storage system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.22.3 Conclusions

The staff reviewed the information in Section 2.3.3.22 and Table 3.3-30, pages 3.3-197 to 198, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the hydrogen bulk storage system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.23 Instrument Air System

3.3.23.1 Technical Information in the Application

The McGuire instrument air system provides dry oil-free air for instrumentation, testing, and control air requirements. The McGuire UFSAR Section 9.3.1, Compressed Air Systems, provides additional information concerning the McGuire instrument air system.

The Catawba instrument air system supplies clean, oil-free, dried, compressed air to all air-operated instrumentation and valves for both units. The Catawba UFSAR Section 9.3.1, Compressed Air System, provides additional information concerning the Catawba instrument air system.

3.3.23.1.1 Aging Effects

Components of the instrument air system are described in Section 2.3.3.23 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-31, pages 3.3-199 to 201, of the LRA lists individual components of the system including filters, accumulators, tanks, pipe, tubing, and valve bodies. Stainless steel components are identified as being subject to an internal environment of air, sheltered environment and reactor building environment with no aging effects identified. Carbon steel components are subject to the aging effect of loss of material from external surfaces exposed to sheltered environments. Carbon steel components are identified as being subject to the internal environment of air with no aging effects identified. Galvanized steel components are subject to the aging effect of loss of material from external surfaces exposed to sheltered environments. Galvanized steel components are identified as being subject to the internal environment of air with no aging effects identified. Brass components are subject to the aging effect of loss of material on external surfaces from exposure to sheltered environment. Internal surfaces of brass components exposed to air are not subject to any aging effects. Copper components are subject to the aging effect of loss of material from external surfaces from exposure to sheltered environments. Internal surfaces of copper components exposed to air are not subject to any aging effects.

3.3.23.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the instrument air system:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the instrument air system will be adequately managed by these aging management programs during the period of extended operation.

3.3.23.2 Staff Evaluation

The applicant described its AMR of the instrument air system for license renewal in two separate sections of its LRA: Section 2.3.3.23 and Table 3.3-31, pages 3.3-199 to 201. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the instrument air system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.23.2.1 Aging Effects

The aging effects that result from contact of the instrument air system SSCs to the environments described in Section 2.3.3.23 and Table 3.3-31, pages 3.3-199 through 3.3-201, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.23.2.2 Aging Management Programs

Section 2.3.3.23 and Table 3.3-31, pages 3.3-199 to 201, of the LRA states that the following aging management programs are credited for managing the aging effects in the instrument air system.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

The Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-31, the staff concludes that the above identified AMPs will effectively manage the aging effects of the instrument air system and that there is reasonable assurance that the intended functions of the instrument air system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.23.3 Conclusions

The staff reviewed the information in Section 2.3.3.23 and Table 3.3-31, pages 3.3-199 to 201, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the instrument air system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.24 Liquid Waste System

3.3.24.1 Technical Information in the Application

The McGuire liquid waste recycle and liquid waste monitor and disposal systems collect, segregate, and process the reactor-grade and non-reactor grade liquid wastes produced during station operation, refueling, or maintenance. Portions of the liquid waste recycle system function as part of the RCS leakage detection systems. The McGuire UFSAR Section 11.2, Liquid Waste System, provides additional information concerning the McGuire liquid waste recycle and liquid waste monitor and disposal systems.

The Catawba liquid radwaste system collects, segregates, and processes all radioactive and potentially radioactive liquids generated in the plant. In general, all reactor grade liquids are recycled and all non-reactor grade liquids are processed and disposed of in accordance with applicable NRC regulations. The system is designed to control and minimize releases of radioactivity to the environment. The Catawba UFSAR Section 11.2, Liquid Radwaste System, provides additional information concerning the Catawba liquid radwaste system.

3.3.24.1.1 Aging Effects

Components of the liquid waste system are described in Section 2.3.3.24 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-32, pages 3.3-202 to 208, of the LRA lists individual components of the system including tanks, pumps, pipe, orifices, separators, strainers, tubing, and valve bodies. Stainless steel components are identified as being subject to the external environments of sheltered and reactor building with no aging effects identified. An internal environment of raw water, borated water, and treated water causes the aging effect of loss of material in stainless steel components. Cracking in stainless steel is also caused by exposure of internal surfaces to borated water and treated water. Internal surfaces of stainless steel components are also subject to the aging effects of cracking (wet/dry) and loss of material (wet/dry) from exposure to a treated water environment. Internal surfaces of stainless steel components exposed to ventilation or gas environments are not subject to any aging effects. Carbon steel components are subject to the aging effect of loss of material from internal environments of raw water and treated water and external surfaces to the environments of reactor building and sheltered environments. Carbon steel components are identified as being subject to the internal environment of gas with no aging effects identified.

3.3.24.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the liquid waste recycle and liquid waste monitor and disposal systems:

- Inspection Program for Civil Engineering Structures and Components
- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Liquid Waste Inspection Program
- Chemistry Control Program
- Flow Accelerated Corrosion Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the liquid waste recycle and liquid waste monitor and disposal systems will be adequately managed by these aging management programs during the period of extended operation.

3.3.24.2 Staff Evaluation

The applicant described its AMR of the liquid waste systems for license renewal in two separate sections of its LRA: Section 2.3.3.24 and Table 3.3-32, pages 3.3-202 to 208. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the liquid waste systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.24.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.24 and Table 3.3-32, pages 3.3-202 to 208, of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3.32-1, additional information pertaining to Table 3.3-32, "Aging Management Review Results - Liquid Waste System." This table indicates that stainless steel piping and loop seals at the McGuire plant have the aging effect of loss of material and cracking due to exposure to wet/dry conditions. The applicant was requested to identify where in the LRA the AMR for the wet/dry aging effect is and explain how the effect is managed by the Chemistry Control Program, or to provide a justification for excluding this environment/aging effect from Table 3.3-32 and an AMR.

In its response dated March 15, 2002, the applicant stated that the aging management review results for the liquid waste system are presented in Table 3.3-32 of the LRA. The components exposed to an alternate wet and dry environment are piping and valves associated with the loop seal shown on drawing MCFD-1565-03.00 at coordinates D-4 and drawing MCFD-2565-03.00 at coordinates L-3. The seal is established by the addition of demineralized water from the demineralized water system to the loop. Loss of material and cracking could occur as a result of the concentration of contaminants from alternate wetting and drying. Demineralized water contains minimal, if any, contaminants and is monitored and controlled by the Chemistry Control Program. Monitoring and controlling the quality of demineralized water used in plant systems such as the liquid waste system loop seal will minimize contaminant levels such that concentrations that could pose a concern can not be achieved through alternate wetting and drying. Therefore, the Chemistry Control Program will mitigate loss of material and cracking of the loop seal components exposed to alternate wetting and drying from demineralized water by monitoring and maintaining the water quality of the demineralized water system. Since the applicant reviewed the aging effect and credits the Chemistry Control Program to manage it, the staff finds its response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.32-2, additional information pertaining to Table 3.3-32, "Aging Management Review Results - Liquid Waste System." This table identifies the aging effect of loss of material and cracking of stainless steel due to exposure to wet/dry conditions. The applicant was requested to clarify if this aging effect is also applicable to the sump pump components identified in Table 3.3-32.

In its response dated March 15, 2002, the applicant stated that Table 3.3-32 of the LRA identified loss of material and cracking of stainless steel pipe and valves at McGuire due to exposure to alternate wet/dry conditions in a treated water environment. Loss of material and cracking of stainless steel due to exposure to wet/dry conditions does not apply to the sump pump components identified in Table 3.3-32. The sump pump components are exposed to a raw water environment only. Since the applicant clarified that the sump pump components are exposed to a raw water environment only, the staff finds its response acceptable.

The staff finds that the applicant’s responses clarify and satisfactorily resolve these items. The aging effects that result from contact of the liquid waste system SSCs to the environments described in Section 2.3.3.24 and Table 3.3-32, pages 3.3-202 through 3.3-208, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.24.2.2 Aging Management Programs

Section 2.3.3.24 and Table 3.3-32, pages 3.3-202 to 208, of the LRA states that the following aging management programs are credited for managing the aging effects in the liquid waste system.

- Inspection Program for Civil Engineering Structures and Components

- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Liquid Waste Inspection Program
- Chemistry Control Program
- Flow Accelerated Corrosion Program

The Fluid Leak Management Program, Galvanic Susceptibility Inspection Program, Chemistry Control Program, Inspection Program for Civil Engineering Structures and Components, Flow Accelerated Corrosion Program, and Liquid Waste System Inspection Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-32, the staff concludes that the above identified AMPs will effectively manage the aging effects of the liquid waste system and that there is reasonable assurance that the intended functions of the liquid waste system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.24.3 Conclusions

The staff reviewed the information in Section 2.3.3.24 and Table 3.3-32 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the liquid waste system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.25 Miscellaneous Structures Ventilation System

3.3.25.1 Technical Information in the Application

The turbine building ventilation system at McGuire performs the corresponding functions as the miscellaneous structures ventilation system at Catawba.

The Catawba miscellaneous structures ventilation system includes the standby shutdown facility (SSF) HVAC. The SSF HVAC portion of the miscellaneous structures ventilation system provides the environmental controls necessary to ensure that SSF equipment is maintained operable during postulated fires and station blackout.

Components of the miscellaneous structures ventilation system are described in Section 2.3.3.25 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-33, page 3.3-209, of the LRA lists individual components of the system including air handling units, ductwork, flexible connectors, and plenum sections. Galvanized steel components exposed to an internal environment of ventilation and sheltered environments are not subject to any aging effects. Neoprene components exposed to ventilation and sheltered environments are not subject to any aging effects.

No AMPs are required to manage aging effects to the miscellaneous structures ventilation system.

3.3.25.2 Staff Evaluation

The applicant described its AMR of miscellaneous structures ventilation system for license renewal in two separate sections of its LRA: Section 2.3.3.25 and Table 3.3-33, page 3.3-209. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the miscellaneous structures ventilation system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.25.2.1 Aging Effects

The applicant's conclusion that no aging effects result from contact of the miscellaneous structures ventilation system SSCs to the environments listed in Section 2.3.3.25 and Table 3.3-33, page 3.3-209, is consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff agrees with the applicant that there are no aging effects for the combination of materials and environments listed.

3.3.25.2.2 Aging Management Programs

There are no aging effects identified in this system. Therefore, no AMPs are required in the miscellaneous structures ventilation system.

3.3.25.3 Conclusions

The staff reviewed the information in Section 2.3.3.25 and Table 3.3-33, page 3.3-209, of the LRA. On the basis of its review, the staff concludes that the SCs in the miscellaneous structures ventilation system are not subject to any aging effects. Therefore, no AMPs are required in the miscellaneous structures ventilation system.

3.3.26 Nitrogen System

3.3.26.1 Technical Information in the Application

The McGuire nitrogen system provides a safety-related supply of nitrogen to the pneumatic actuators on the feedwater isolation valves.

The Catawba nitrogen system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of these systems are within the scope of license renewal per §54.4(a)(2).

Components of the nitrogen system are described in Section 2.3.3.26 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-34, page 3.3-210, of the LRA lists individual components of the system including tanks, pipe, tubing, and valve bodies.

Stainless steel components exposed to gas (internal environment) and a sheltered external environment are not subject to any aging effects.

No AMPs are required to manage aging effects to the nitrogen system.

3.3.26.2 Staff Evaluation

The applicant described its AMR of the nitrogen system for license renewal in two separate sections of its LRA: Section 2.3.3.26 and Table 3.3-34, page 3.3-210. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the nitrogen system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.26.2.1 Aging Effects

The staff reviewed the applicant's response to RAI 2.3.3.26-2, which provided AMR results for additional components (valve bodies and tubing associated with the safety-related SG PORV back-up control system) that were identified by the applicant as within the scope of license renewal (documented in Section 2.3.3.26.2 of this SER). The applicant's conclusion that no aging effects result from contact of the miscellaneous structures ventilation system SSCs to the environments listed in the RAI response and in LRA Section 2.3.3.26 and Table 3.3-34, on page 3.3-210, is consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff agrees with the applicant that there are no aging effects for the combination of materials and environments listed.

3.3.26.2.2 Aging Management Programs

There are no aging effects identified in this system. Therefore, no AMPs are required in the nitrogen system.

3.3.26.3 Conclusions

The staff reviewed the information in the applicant's response to RAI 2.3.3.26-2 and Section 2.3.3.26 and Table 3.3-34, page 3.3-210, of the LRA. On the basis of its review, the staff concludes that the SCs in the nitrogen system are not subject to any aging effects. Therefore, no AMPs are required for the nitrogen system.

3.3.27 Nuclear Sampling System

3.3.27.1 Technical Information in the Application

The nuclear sampling system is essentially the same and performs the same function for McGuire and Catawba. The nuclear sampling system provides a means of obtaining the more frequently taken samples during normal plant operation from the station's nuclear-safety related systems in a convenient, shielded, and safe environment. The system also provides a means of sampling the reactor coolant and containment atmosphere following a loss-of-coolant-accident (LOCA) to monitor the reactor and determine the degree of core damage. The McGuire UFSAR Section 9.3.2, Nuclear Sampling System, provides additional information concerning the McGuire nuclear sampling system. The Catawba UFSAR Section

9.3.2, Process Sampling and Post-Accident Sampling Systems, provides additional information concerning the Catawba Nuclear Sampling System.

Components of the nuclear sampling system are described in Section 2.3.3.27 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-35, pages 3.3-211 to 213, of the LRA lists individual components of the system including orifices, pipe, tubing, and valve bodies. Stainless steel components are identified as being subject to the external environments of sheltered and reactor building with no aging effects identified. An internal environment of borated water and treated water causes the aging effect of loss of material and cracking in stainless steel components. Internal surfaces of stainless steel components exposed to gas environments are not subject to any aging effects.

The following AMP is utilized to manage aging effects to the nuclear sampling system:

- Chemistry Control Program

The Chemistry Control Program is credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff's review of the common aging management programs is documented in Section 3.0 of the SER.

A description of the aging management program is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the nuclear sampling system will be adequately managed by the aging management program during the period of extended operation.

3.3.27.2 Staff Evaluation

The applicant described its AMR of the nuclear sampling system for license renewal in two separate sections of its LRA: Section 2.3.3.27 and Table 3.3-35, pages 3.3-211 to 213. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the nuclear sampling system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.27.2.1 Aging Effects

The aging effects that result from contact of the nuclear sampling system SSCs to the environments described in Section 2.3.3.27 and Table 3.3-35, pages 3.3-211 through 3.3-213, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.27.2.2 Aging Management Programs

Section 2.3.3.27 and Table 3.3-35, pages 3.3-211 to 213, of the LRA states that the following aging management program is credited for managing the aging effects in the nuclear sampling system.

- Chemistry Control Program

The Chemistry Control Program is credited with managing the aging effects of several components in different structures and systems and is, therefore, considered a common aging management program. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-35, the staff concludes that the above identified AMP will effectively manage the aging effects of the nuclear sampling system and that there is reasonable assurance that the intended functions of the nuclear sampling system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.27.3 Conclusions

The staff reviewed the information in Section 2.3.3.27 and Table 3.3-35, pages 3.3-211 to 213, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the nuclear sampling system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.28 Nuclear Service Water System

3.3.28.1 Technical Information in the Application

The McGuire nuclear service water system provides cooling water from Lake Norman or the standby nuclear service water pond to various safety-related and non-safety related heat exchangers. In addition, the system acts as an assured source of makeup water for various requirements and the normal supply of water for the containment ventilation cooling water system. The McGuire UFSAR Section 9.2.2, Nuclear Service Water System and Ultimate Heat Sink, provides additional information concerning the McGuire nuclear service water system.

The Catawba nuclear service water system, along with Lake Wylie and the standby nuclear service water pond, provides the ultimate heat sink for various safety-related heat loads during normal operation and design basis events. The nuclear service water system also supplies emergency makeup water to various safety-related systems during postulated design basis events, water for fire protection hose stations in the diesel buildings and nuclear service water pumphouse, and cooling flow and flush water for non-QA heat loads and functions during normal operation. The Catawba UFSAR Section 9.2.1, Nuclear Service Water System, provides additional information concerning the Catawba nuclear service water system.

3.3.28.1.1 Aging Effects

Components of the nuclear service water system are described in Section 2.3.3.28 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-36, pages 3.3-214 to 221 (McGuire Nuclear Station), and Table 3.3.37, pages 3.3-222 to 228 (Catawba Nuclear Station), of the LRA lists individual components of the system including oil coolers, expansion joints, pump casings, strainers, orifices, pipe, tubing, annubars, flexible hoses, manways, and valve bodies. Stainless steel components are identified as being subject to the external environments of sheltered, reactor building, yard, and oil with no aging effects identified. Stainless steel components identified as being subject to the external environment of underground are subject to the aging effect of loss of material and cracking. An internal environment of raw water causes the aging effect of loss of material in stainless steel components. Internal surfaces of stainless steel components exposed to oil environments are not subject to any aging effects. Internal or external surfaces of carbon steel components exposed to raw water, reactor building, underground, yard, or sheltered environments are subject to the aging effect of loss of material. Copper nickel components exposed to an internal environment of raw water are subject to fouling and/or loss of material. Exposure of copper nickel components to an external oil environment has no aging effect. Brass components exposed to an internal environment of raw water are subject to loss of material. Exposure of brass components to an external environment of oil has no aging effect. Cast iron components exposed to internal or external environments of raw water or sheltered are subject to loss of material.

3.3.28.1.2 Aging Management Programs

The following AMP is utilized to manage aging effects to the nuclear service water system:

- Heat Exchanger Preventive Maintenance Activities - Pump Oil Coolers
- Service Water Piping Corrosion
- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- Preventive Maintenance Activities - Condenser Circulation Water System Internal Coating Inspection
- Selective Leaching Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the nuclear service water system will be adequately managed by these aging management programs during the period of extended operation.

3.3.28.2 Staff Evaluation

The applicant described its AMR of the nuclear service water system for license renewal in two separate sections of its LRA: Section 2.3.3.28 and Table 3.3-36, pages 3.3-214 to 221, and Table 3.3.37, pages 3.3-222 to 228. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the nuclear service water system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.28.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.28 and Table 3.3-36, pages 3.3-214 to 221, and Table 3.3.37, pages 3.3-222 to 228, of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI-3.3.36-1, additional information pertaining to Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear

Station)." This table indicates that centrifugal and reciprocating charging pumps and safety injection pump oil coolers (tubes and tube sheets) have a raw water internal/external environment with an oil internal/external environment. No aging effect is identified for these environments. Oil systems subject to water contamination are typically subject to the aging effect of loss of material. The applicant was requested to identify where in the LRA the AMR results are for the aging effect of loss of material from general, pitting, crevice, and microbiologically influenced corrosion to stainless steel and copper-nickel materials for oil coolers potentially contaminated with leaking water, or to provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

In its response dated March 15, 2002, the applicant stated that all of the lube oil cooler components cited in RAI 3.3.36-1 are components of closed oil recirculation systems. Uncontaminated lube oil does not cause aging, and closed oil recirculation systems are assumed to be initially free of contaminants such as water. Further, in the Duke aging management review, component failures were not postulated as a means to establish the relevant conditions required for aging to occur. Therefore, in oil coolers, tube failures that could introduce water into a lube oil environment are not assumed.

By electronic correspondence, dated May 2, 2002, the staff commented on the applicant's response, indicating that all systems are designed initially to be leak tight, but failures in a heat exchanger system during the lifetime of the system cannot be ruled out. In fact, industry operating experience indicates that oil periodically is contaminated with cooling water. Furthermore, leakage of water into oil systems may not involve component failures per se, but minor breaches in component pressure boundaries that may go undetected and allow corrosion and other forms of degradation to progress indefinitely (which is why plants implement surveillance monitoring programs for oil lubricating and fuel oil systems). The staff further noted that the GALL report also addresses this aging effect for oil environments.

In electronic correspondence dated May 10, 2002 (ML021440236), the applicant responded that Duke is assuming that the staff believes breaches of the pressure boundary in the oil coolers are the result of aging of the raw water side of the cooler that allows raw water to contaminate the oil. Duke reiterates that component failures due to aging were not postulated as a means to establish the relevant conditions required for aging to occur. For the oil coolers in question, Duke identified the aging that could occur in the normal environment. No aging effects were identified for the cooler components exposed to uncontaminated oil.

The applicant further stated that aging effects were identified for the cooler components exposed to raw water that left unmanaged could result in a loss of the pressure boundary function. Duke credited the Heat Exchanger Preventive Maintenance Activities - Pump Oil Coolers described in Section B.3.17.7 of the LRA to maintain the pressure boundary integrity to prevent the contamination of the oil system. Industry operating experience indicates the need for such a monitoring program. Plant specific operating experience also demonstrates that the aging management program credited has been and will continue to be effective during the period of extended operation. By letter from the applicant dated July 9, 2002, the staff received this information in official correspondence. The applicant was able to demonstrate that aging effects of the cooler components exposed to raw water will be adequately managed to maintain the pressure boundary integrity to prevent the contamination of the oil system. The staff agrees that uncontaminated oil will not cause any aging effect to the components and that the applicant is not required to assume a failure that can cause an aging effect. Therefore, this issue is resolved.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.36-2, additional information pertaining to Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station)." This table indicates that the copper-nickel centrifugal and reciprocating charging pump and safety injection pump bearing oil cooler and centrifugal charging pump speed reducer oil cooler tubes are subject to an internal environment of raw water. The applicant was requested to identify where in the LRA the AMR results are for the aging effect of selective leaching for copper-nickel components in a raw water environment, or to provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

In its response dated March 15, 2002, the applicant stated that the relevant conditions required for loss of material due to selective leaching to occur in copper-nickel alloys are a temperature greater than 212 °F, low flow, and high local heat fluxes. These conditions are not found in the nuclear service water system. Therefore, loss of material due to selective leaching is not an aging effect requiring management during the period of extended operation for copper-nickel alloy components exposed to raw water.

In electronic correspondence dated May 2, 2002, the staff commented on the applicant's response, stating that service water inspections and industry experience from ANO-1 indicates that even under high flow conditions the impurity, chloride biocide, in the systems resulted in de-nickelification to the 90/10 copper nickel heat exchanger tubes where 70/30 copper nickel may have been less susceptible to the selective leaching aging effect. The staff further noted that the copper content of the component is a significant contributor to material vulnerability independent of temperature and flow conditions.

In electronic correspondence dated May 10, 2002 (ML021440236), the applicant replied that Duke believes that the industry experience from ANO-1 is not relevant to the McGuire Nuclear Service Water System. The McGuire Nuclear Service Water System is an untreated open-cycle cooling water system. The operating experience presented notes that selective leaching occurred as a result of the chlorine biocide. Duke does not use chlorine biocides in the McGuire Nuclear Service Water System. Therefore, selective leaching of copper-nickel alloys is not a concern. By letter from the applicant dated July 9, 2002, the staff received this information in official correspondence. Since the applicant demonstrated that McGuire operating practices precluded selective leaching as a result of chlorine biocide, this issue is resolved.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.36-3, additional information pertaining to Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station)." This table indicates that the copper-nickel reciprocating charging pump bearing oil cooler and fluid drive oil cooler tubes are subject to an internal environment of raw water. The applicant was requested to identify where in the LRA the AMR for the aging effect of fouling for the copper-nickel tubes in a raw water environment is, or to provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

In its response dated March 15, 2002, the applicant stated that the reciprocating charging pumps are not relied upon for any event at McGuire Nuclear Station. The nuclear service water side of the reciprocating charging pump bearing oil cooler and fluid drive oil cooler is only in scope because it is associated with Class F piping, and therefore meets the criteria of §54.4(a)(2). Loss of pressure boundary integrity could prevent satisfactory accomplishment of a safety function. Only the pressure boundary integrity of the reciprocating charging pump bearing oil cooler and fluid drive oil cooler is required to be maintained; heat transfer is not a function of the tubes. Fouling can cause a loss of heat transfer function, but does not affect the pressure boundary function of the reciprocating charging pump bearing oil cooler and fluid drive oil cooler tubes. Therefore, fouling is not an aging effect requiring management during the period of extended operation. The staff finds this a logical explanation of why fouling is not identified as an aging effect for the copper-nickel tubes. The staff agrees with the applicant that fouling is not an applicable aging effect since the system does not perform a heat transfer function.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.36-4, additional information pertaining to Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station)." This table indicates that the cast iron reciprocating charging pump fluid drive oil cooler channel covers are subject to an internal environment of raw water. The applicant was requested to identify where in the LRA the AMR results are for the aging effect of selective leaching for cast iron components in a raw water environment is, or to provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

In its response dated March 15, 2002, the applicant stated that loss of material due to selective leaching is an aging effect applicable only to "gray" cast iron. The reciprocating charging pump fluid drive oil cooler channel covers are constructed of "long black iron," which is carbon steel. Therefore, loss of material due to selective leaching is not an aging effect requiring management during the period of extended operation for the channel covers in Table 3.3-36 of the LRA. The Table 3.3-36 entry for the "Reciprocating Charging Pump Fluid Drive Oil Coolers (channel covers)" is in error. The Table 3.3-36 entry for the "Reciprocating Charging Pump Fluid Drive Oil Coolers (channel covers)" was revised to reflect the correct material for these channel covers, which is carbon steel. Since the applicant clarified that the component material is carbon steel, the staff agrees that loss of material due to selective leaching is not an applicable aging effect.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.37-1, additional information pertaining to Table 3.3.37, "Aging Management Review Results - Nuclear Service Water System (Catawba Nuclear Station)." On pages 3.3-214 through 3.3-228 of the LRA, the applicant indicated that loss of material from pitting corrosion is an applicable aging effect for admiralty brass, brass, bronze, carbon steel, cast iron, copper, 90-10 copper-nickel, ductile cast iron, and stainless steel materials in a raw water environment. Pitting corrosion can be inhibited by maintaining an adequate flow rate, which prevents impurities from adhering to the material surface. The more susceptible locations for pitting corrosion to occur in materials in a raw water environment are locations of low or stagnant flow. The applicant was requested to identify where in the LRA the AMR results are for the aging effect of pitting corrosion in low flow or stagnant conditions, or to provide a justification for excluding this aging effect from Table 3.3-37 and an AMR.

In its response dated March 15, 2002, the applicant stated that in the Duke aging management review, pitting corrosion is considered an aging mechanism that manifests itself as loss of material. Loss of material is the aging effect requiring management for license renewal. Loss of material is identified in Table 3.3-36 for all applicable materials exposed to raw water and is managed by the “Service Water Piping Corrosion Program.” The staff verified that the Service Water Piping Corrosion Program will manage loss of material. However, the applicant should justify how its program will manage the effects of localized corrosion caused by pitting and MIC to ensure that the intended pressure boundary function is provided during all design basis events consistent with the CLB throughout the extended period of operating, as required by 10 CFR 54.21(a)(3). This issue is characterized as open item 3.0.3.15.2-1 and is discussed in detail in Section 3.0.3.15.2 of this SER.

The staff finds that the applicant's responses to RAI 3.3.36-3, 3.3.36-4, and 3.3.37-1 clarify and satisfactorily resolve these items. The aging effects that result from contact of the nuclear service water system SSCs to environments as described in Section 2.3.3.28 and Table 3.3-36, pages 3.3-214 to 221, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.28.2.2 Aging Management Programs

Section 2.3.3.28 and Table 3.3-36, pages 3.3-214 to 221, of the LRA states that the following aging management programs are credited for managing the aging effects in the nuclear service water system.

- Heat Exchanger Preventive Maintenance Activities - Pump Oil Coolers
- Service Water Piping Corrosion
- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- Preventive Maintenance Activities - Condenser Circulation Water System Internal Coating Inspection
- Selective Leaching Inspection

The Fluid Leak Management Program, Galvanic Susceptibility Inspection Program, Service Water Piping Corrosion Program, Inspection Program for Civil Engineering Structures and Components, Preventive Maintenance Activities - Condenser Circulation Water System Internal Coating Inspection Program, and Selective Leaching Inspection Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and, with the exception of open item 3.0.3.9.1.2(b) pertaining to the Heat Exchanger Preventive Maintenance Activities - Pump Oil Coolers, open item 3.0.3.13.2-1 pertaining to the Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection program, and open item 3.0.3.15.2-1 pertaining to the Service Water Piping Corrosion program, found them to be acceptable for managing the aging effects identified for this system. The staff’s evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-37, with the exception of open items 3.0.3.9.1.2(b), 3.0.3.13.2-1, and 3.0.3.15.2-1, the staff concludes that the above identified AMPs will effectively manage the aging effects of the nuclear service water system and that there is reasonable assurance that the intended functions of the nuclear service water system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.28.3 Conclusions

The staff reviewed the information in Section 2.3.3.28 and Table 3.3-37 of the LRA. On the basis of its review, with the exception of open items 3.0.3.9.1.2(b), 3.0.3.13.2-1, and 3.0.3.15.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the nuclear service water system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.29 Nuclear Service Water Pump Structure Ventilation System (Catawba Only)

3.3.29.1 Technical Information in the Application

No system corresponding to the Catawba nuclear service water pump structure ventilation system exists at McGuire. McGuire has no nuclear service water pump structure.

The Catawba nuclear service water pump structure ventilation system creates and maintains a suitable environmental temperature for the operation of equipment located in the nuclear service water pump structure. The Catawba UFSAR Section 9.4.8, Nuclear Service Water Pump Structure Ventilation System, provides additional information concerning the Catawba nuclear service water pump structure ventilation system.

3.3.29.1.1 Aging Effects

Components of the nuclear service water pump structure ventilation system are described in Section 2.3.3.29 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-38, pages 3.3-229 to 230, of the LRA lists individual components of the system including ductwork, pipe, tubing, and valve bodies. Galvanized steel, brass, copper, or stainless steel components exposed to ventilation and sheltered environments are not subject to any aging effects. Carbon steel components exposed to sheltered environments demonstrate loss of material. Exposure of carbon steel to an internal environment of ventilation has no aging effect.

3.3.29.1.2 Aging Management Programs

The following AMP is utilized to manage aging effects to the nuclear service water pump structure ventilation system:

- Inspection Program for Civil Engineering Structures and Components

A description of the aging management program is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the nuclear service water pump structure ventilation system will be adequately managed by the aging management program during the period of extended operation.

3.3.29.2 Staff Evaluation

The applicant described its AMR of the nuclear service water pump structure ventilation system for license renewal in two separate sections of its LRA: Section 2.3.3.29 and Table 3.3-38, pages 3.3-229-230. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the nuclear service water pump structure ventilation system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.29.2.1 Aging Effects

The aging effects that result from contact of the nuclear service water pump structure ventilation system SSCs to the environments described in Section 2.3.3.29 and Table 3.3-38, pages 3.3-229 through 3.3-230, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.29.2.2 Aging Management Programs

Section 2.3.3.29 and Table 3.3-38, pages 3.3-229 to 230, of the LRA states that the following aging management program is credited for managing the aging effects in the nuclear service water pump structure ventilation system.

- Inspection Program for Civil Engineering Structures and Components

The Inspection Program for Civil Engineering Structures and Components is credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-38, the staff concludes that the above identified AMP will effectively manage the aging effects of the nuclear service water pump structure ventilation system and that there is reasonable assurance that the intended functions of the nuclear service water pump structure ventilation system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.29.3 Conclusions

The staff reviewed the information in Section 2.3.3.29 and Table 3.3-38, pages 3.3-229 to 230, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with nuclear service water pump structure ventilation system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.30 Nuclear Solid Waste Disposal System

3.3.30.1 Technical Information in the Application

The McGuire nuclear solid waste disposal system is relied upon to contain solid radioactive waste materials as they are produced in the station. The McGuire UFSAR Section 11.5, Nuclear Solid Waste Disposal System, provides additional information concerning the McGuire nuclear solid waste disposal system.

The Catawba solid radwaste system provides capacity to contain and store radioactive waste materials as they are produced in the station and prepares the waste for eventual shipment to a licensed offsite disposal facility. The solid radwaste system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this system are within the scope of license renewal per §54.4(a)(2).

3.3.30.1.1 Aging Effects

Components of the nuclear solid waste disposal system are described in Section 2.3.3.30 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-39, pages 3.3-231 to 233, of the LRA lists individual components of the system including screens, resin storage tanks, pipe, tubing, and valve bodies. Stainless steel components are identified as being subject to the external environments of sheltered and gas with no aging effects identified. Internal or external environments of treated water cause the aging effects loss of material and cracking in stainless steel components. Internal surfaces of stainless steel components exposed to gas environments are not subject to any aging effects.

3.3.30.1.2 Aging Management Programs

The following AMP is utilized to manage aging effects to the nuclear solid waste disposal system:

- Treated Water Systems Stainless Steel Inspection

A description of the aging management program is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the solid waste disposal system will be adequately managed by the aging management program during the period of extended operation.

3.3.30.2 Staff Evaluation

The applicant described its AMR of the nuclear solid waste disposal system for license renewal in two separate sections of its LRA: Section 2.3.3.30 and Table 3.3-39, pages 3.3-231 to 233. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the nuclear solid waste disposal system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.30.2.1 Aging Effects

The aging effects that result from contact of the nuclear solid waste disposal system SSCs to the environments described in Section 2.3.3.30 and Table 3.3-39, pages 3.3-231 through 3.3-233, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.30.2.2 Aging Management Programs

Section 2.3.3.30 and Table 3.3-39, pages 3.3-231 to 233, of the LRA states that the following aging management program is credited for managing the aging effects in the nuclear solid waste disposal system.

- Treated Water Systems Stainless Steel Inspection

The Treated Water Systems Stainless Steel Inspection Program is credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-39, the staff concludes that the above identified AMP will effectively manage the aging effects of the nuclear solid waste disposal system and that there is reasonable assurance that the intended functions of the nuclear solid waste disposal system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.30.3 Conclusions

The staff reviewed the information in Section 2.3.3.30 and Table 3.3-39, pages 3.3-231 to 233, of the LRA. On the basis of its review the staff concludes that the applicant has demonstrated that the aging effects associated the nuclear solid waste disposal system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.31 Reactor Coolant Pump Motor Oil Collection Sub-System

3.3.31.1 Technical Information in the Application

Each reactor coolant pump motor at McGuire and Catawba is equipped with an oil collection system that contains any oil leakage.

3.3.31.1.1 Aging Effects

Components of the reactor coolant pump motor oil collection sub-system are described in Section 2.3.3.31 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-40, pages 3.3-234 to 238, of the LRA lists individual components of the system including flexible hoses, level gauges, drain tanks, pump casings, oil catchers, oil pots, oil lift enclosures, pipe, and valve bodies. Exposure of internal and external surfaces of stainless steel to ventilation, reactor building, and sheltered environments has no aging effect. Exposure of carbon steel to external environments of reactor building, and sheltered environments demonstrate loss of material. Exposure of internal surfaces of carbon steel components to ventilation environments has no aging effect. Cast iron components exposed to external reactor building environment demonstrate loss of material. Cast iron exposed to a ventilation environment has no aging effect. Glass components exposed to ventilation and reactor building environments are not subject to any aging effects.

3.3.31.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the reactor coolant pump motor oil collection sub-system:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the reactor coolant pump motor oil collection sub-system will be adequately managed by these aging management programs during the period of extended operation.

3.3.31.2 Staff Evaluation

The applicant described its AMR of the reactor coolant pump motor oil collection sub-system for license renewal in two separate sections of its LRA: Section 2.3.3.31 and Table 3.3-40, pages 3.3-234 to 238. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the reactor coolant pump motor oil collection sub-system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.31.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.31 and Table 3.3-40, pages 3.3-234 to 238, of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3.40-1, additional information pertaining to Table 3.3-40, "Aging Management Review Results - Reactor Coolant Pump Motor Oil Collection Sub-System." This table indicates that flexible hoses are of the material type of stainless steel. Per CN-1553-1.3 and CN-2553.1-3, "Flow Diagram of Reactor Coolant System (NC)," line listings for the flexible hoses between the upper bearing oil enclosures and the reactor coolant pump motor drain tank are carbon steel. The applicant was requested to identify where in the LRA the AMR results are for the reactor coolant pump motor oil collection sub-system carbon steel flexible hoses, or to provide a justification for excluding these components from Table 3.3-40 and an AMR.

In its response dated March 15, 2002, the applicant stated that in general, the materials identified in the line listings on Duke flow diagrams refer to pipe and pipe components and would be generally used for other system components. Materials for some engineered components may be different than the general system material, as is the case here. All of the flexible hoses shown on flow diagrams CN-1553-1.3 and CN-2553-1.3 are stainless steel. No carbon steel flexible hoses are installed within the license renewal evaluation boundaries of the reactor coolant pump motor oil collection sub-system. Since the applicant clarified that the components are made of stainless steel, the staff finds its response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.40-2, additional information pertaining to Table 3.3-40, "Aging Management Review Results - Reactor Coolant Pump Motor Oil Collection Sub-System." This table indicates that all components are subject to an internal environment of ventilation and an external environment of reactor building or ventilation. The applicant was requested to explain why these components of the reactor coolant pump motor oil collection sub-system are not subject to an internal and/or external environment of oil.

In its response dated March 15, 2002, the applicant stated that, in accordance with plant directives and procedures, the reactor coolant pump motor oil collection sub-system is not allowed to be used as an oil storage system. Any used oil that has collected in the drain tank during operation is drained from the system during each refueling outage, and the system is flushed before returning to service following the outage. Therefore, the internal environment of the system at the beginning of each operating cycle is air that enters the system from the reactor building environment during the fill, drain and flush operations, and oil leakage is not expected as a normal operating condition. Since the collected oil will be drained from the system during each outage, and the system is flushed before it is returned to service, the staff agrees that the applicant is not required to assume contamination of internal environment with oil leakage.

The staff finds that the applicant’s responses clarify and satisfactorily resolve these items. The aging effects that result from contact of the reactor coolant pump motor oil collection sub-system SSCs to the environments described in Section 2.3.3.31 and Table 3.3-40, pages 3.3-234 through3.3-238, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.31.2.2 Aging Management Programs

Section 2.3.3.31 and Table 3.3-40, pages 3.3-234 to 238, of the LRA states that the following aging management programs are credited for managing the aging effects in the reactor coolant pump motor oil collection sub-system.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

The Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-40, the staff concludes that the above identified AMPs will effectively manage the aging effects of the reactor coolant pump motor oil collection sub-system and that there is reasonable assurance that the intended functions of the reactor coolant pump motor oil collection sub-system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.31.3 Conclusions

The staff reviewed the information in Section 2.3.3.31 and Table 3.3-40 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the reactor coolant pump motor oil collection sub-system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.32 Reactor Coolant System (Non-Class 1 Components)

3.3.32.1 Technical Information in the Application

The non-class 1 portions of the RCS (excluding the RCP motor oil collection sub-system) are essentially the same and perform the same function for McGuire and Catawba. The non-class 1 portions of the RCS are relied upon to provide and maintain containment isolation and closure and maintain system pressure boundary integrity. The reactor vessel leak-off line is included within this set of components and is relied upon only in the event the reactor vessel flange inner seal leaks.

3.3.32.1.1 Aging Effects

Components of the RCS (non-class 1 components) are described in Section 2.3.3.32 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-41, pages 3.3-239 to 241, of the LRA lists individual components of the system including orifices, pipe, tubing, and valve bodies. Stainless steel components are identified as being subject to the internal or external environments of reactor building, sheltered and gas with no aging effects identified. Stainless steel components exposed to borated water environments demonstrate loss of material and cracking. Carbon steel components are subject to the aging effect of loss of material from external surfaces exposed to sheltered environments. Carbon steel components are identified as being subject to the internal environment of gas with no aging effects identified.

3.3.32.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the RCS (non-class 1 components):

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Chemistry Control Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the RCS (non-class 1 components) will be adequately managed by these aging management programs during the period of extended operation.

3.3.32.2 Staff Evaluation

The applicant described its AMR of the RCS (non-class 1 components) for license renewal in two separate sections of its LRA: Section 2.3.3.32 and Table 3.3-41, pages 3.3-239 to 241. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the RCS (non-class 1 components) will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.32.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.32 and Table 3.3-41, pages 3.3-239 to 241, of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated in January 23, 2002, the staff requested, in RAI 3.3.41-1, additional information pertaining to Table 3.3-41, "Aging Management Review Results - Reactor Coolant System (Non-Class 1 Components)." This table refers to “Note 3,” which states that orifices may be subjected to a borated water or steam environment. The applicant was requested to identify where in the LRA the AMR results are for the RCS orifices in a borated water or steam environment, or to provide a justification for excluding these environments from Table 3.3-41 and an AMR.

In its response dated March 15, 2002, the applicant stated that the orifice listed in Table 3.3-41 of the LRA is located in the common reactor vessel high-point vent line, downstream from the parallel, redundant vent line isolation valve sets, which are isolated during normal plant operation. These orifices are depicted on drawings MCFD 1553-2.01 (at K-6), MCFD-2553-2.01 (at K-6), CN-1553-1.1 (at K-7), and CN-2553-1.1 (at K-7). The vent line is normally used only during system fill operations to vent gases from the RCS to the pressurizer relief tank or during an accident to ensure that voiding does not occur in the reactor vessel head. The orifice and downstream piping between the orifice and the pressurizer relief tank are open to the pressurizer relief tank environment. As a result, the orifice is exposed to the gas environment normal to the pressurizer relief tank. Therefore, the aging management review was performed for a "gas" environment. “Note 3" should not have been included at the end of Table 3.3-41. Since the orifice listed in Table 3.3-41 of the LRA is only subject to an gas environment, and the applicant has corrected the error in "Note 3", the staff finds that the applicant's response clarifies and satisfactorily resolves this item.

The aging effects that result from contact of the RCS (non-class 1 components) SSCs to the environments described in Section 2.3.3.32 and Table 3.3-41, pages 3.3-239 through 3.3-241, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.32.2.2 Aging Management Programs

Section 2.3.3.32 and Table 3.3-41, pages 3.3-239 to 241, of the LRA states that the following aging management programs are credited for managing the aging effects in the RCS (non-class 1 components).

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Chemistry Control Program

The Fluid Leak Management Program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-41, the staff concludes that the above identified AMPs will effectively manage the aging effects of the RCS (non-class 1 components) and that there is reasonable assurance that the intended functions of the RCS (non-class 1 components) will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.32.3 Conclusions

The staff reviewed the information in Section 2.3.3.32 and Table 3.3-41 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the RCS (non-class 1 components) will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.33 Recirculated Cooling Water System (Catawba Nuclear Station Only)

3.3.33.1 Technical Information in the Application

No portion of the McGuire recirculated cooling water system is within the scope of license renewal. Only the Duke Class F portions of the recirculated cooling water system are in scope at Catawba. McGuire has no Class F components in the recirculated cooling water system.

The Catawba recirculated cooling water system is a closed cooling system that delivers clean, rust-inhibited cooling water of a regulated temperature to various equipment in the Turbine Buildings, Auxiliary Building, and Service Building. The recirculated cooling water system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this system are within the scope of license renewal per §54.4(a)(2).

3.3.33.1.1 Aging Effects

Components of the recirculated cooling water system are described in Section 2.3.3.33 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-42, page 3.3-242, of the LRA lists individual components of the system including pipe and valve bodies. Carbon steel components are subject to the aging effect of loss of material from external surfaces exposed to the sheltered environments. Carbon steel components are identified as being subject to loss of material and cracking from exposure to the internal environment treated water.

3.3.33.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to recirculated cooling water system:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Chemistry Control Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the recirculated cooling water system will be adequately managed by these aging management programs during the period of extended operation.

3.3.33.2 Staff Evaluation

The applicant described its AMR of the recirculated cooling water system for license renewal in two separate sections of its LRA: Section 2.3.3.33 and Table 3.3-42, page 3.3-242. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the recirculated cooling water system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.33.2.1 Aging Effects

The aging effects that result from contact of the recirculated cooling water system SSCs to the environments described in Section 2.3.3.33 and Table 3.3-42, page 3.3-242, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.33.2.2 Aging Management Programs

Section 2.3.3.33 and Table 3.3-42, page 3.3-242, of the LRA states that the following aging management programs are credited for managing the aging effects in the recirculated cooling water system.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Chemistry Control Program

The Fluid Leak Management Program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-42, the staff concludes that the above identified AMPs will effectively manage the aging effects of the recirculated cooling water system and that there is reasonable assurance that the intended functions of the recirculated cooling water system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.33.3 Conclusions

The staff reviewed the information in Section 2.3.3.33 and Table 3.3-42, page 3.3-242, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the recirculated cooling water system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.34 Spent Fuel Cooling System

3.3.34.1 Technical Information in the Application

The McGuire spent fuel cooling system removes heat from the spent fuel pool and maintains the purity and optical clarity of the pool water for fuel handling operations. The purification loop provides an alternate means for removing impurities from either the refueling canal/transfer canal water during refueling or the refueling water storage tank water following refueling. The fuel pool water also serves as a source of makeup water to the RCS during a standby shutdown system event. The McGuire UFSAR Section 9.1.3, Spent Fuel Cooling and Purification, provides additional information concerning the McGuire spent fuel cooling system.

The Catawba spent fuel cooling system, in conjunction with the component cooling water system and nuclear service water system, is designed to remove heat from the spent fuel pool and maintain purity and optical clarity of the pool water during fuel handling operations. The purification loop provides an alternate means for removing impurities from either the refueling cavity/transfer canal water during refueling or the refueling water storage tank water following refueling. The Catawba UFSAR Section 9.1.3, Spent Fuel Cooling and Purification, provides additional information concerning the Catawba spent fuel cooling system.

3.3.34.1.1 Aging Effects

Components of the spent fuel cooling system are described in Section 2.3.3.34 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-43, pages 3.3-243 to 246, of the LRA lists individual components of the system including heat exchangers, channel heads, shells, tubes, and tube sheets, orifices, pump casings, spacers, pipe, tubing, and valve bodies. Stainless steel components are identified as being subject to the external environments of sheltered and reactor building with no aging effects identified. An internal or external environment of borated water or treated water causes the aging effect of loss of material and cracking in stainless steel components. Carbon steel components are subject to the aging effect of loss of material and cracking from exposure to internal and external surfaces from treated water environments. Carbon steel components are identified as being subject to loss of material from sheltered environments.

3.3.34.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the spent fuel cooling system:

• Inspection Program for Civil Engineering Structures and Components
• Fluid Leak Management Program
• Chemistry Control Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the spent fuel cooling system will be adequately managed by these aging management programs during the period of extended operation.

3.3.34.2 Staff Evaluation

The applicant described its AMR of the spent fuel cooling system for license renewal in two separate sections of its LRA: Section 2.3.3.34 and Table 3.3-43, pages 3.3-243 to 246. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the spent fuel cooling system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.34.2.1 Aging Effects

The aging effects that result from contact of the spent fuel cooling system SSCs to the environments described in Section 2.3.3.34 and Table 3.3-43, pages 3.3-243 through 3.3-246, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.34.2.2 Aging Management Programs

Section 2.3.3.34 and Table 3.3-43, pages 3.3-243 to 246, of the LRA states that the following aging management programs are credited for managing the aging effects in the spent fuel cooling system.

• Inspection Program for Civil Engineering Structures and Components
• Fluid Leak Management Program
• Chemistry Control Program

The Fluid Leak Management Program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-43, the staff concludes that the above identified AMPs will effectively manage the aging effects of the spent fuel cooling system and that there is reasonable assurance that the intended functions of the spent fuel cooling system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.34.3 Conclusions

The staff reviewed the information in Section 2.3.3.34 and Table 3.3-43, pages 3.3-243 to 246, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the spent fuel cooling system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.35 Standby Shutdown Diesel

3.3.35.1 Technical Information in the Application

The standby shutdown diesel system is essentially the same and performs the same function for McGuire and Catawba. The standby shutdown diesel system provides an alternate and independent means of achieving and maintaining a hot standby condition for one or both units following a postulated fire event. The diesel provides power to the standby shutdown facility required components, instrumentation, and controls for a period of up to 72 hours.

3.3.35.1.1 Aging Effects

Components of the standby shutdown diesel system are described in Section 2.3.3.35 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-44, pages 3.3-247 to 255, of the LRA lists individual components of the system including cooling water filters, heat exchanger engine radiators, tubing, valve bodies, exhaust bellows, piping, silencers, duplex filters, flame arrestors, level glass, pipe, oil storage tanks, tank vents, pump casings, and oil filters. Stainless steel components exposed to internal environments of ventilation, yard, or sheltered exhibit no aging effects. Stainless steel components exposed to internal or external environments of fuel oil are subject to the loss of material aging effect. Stainless steel exposed to an underground environment exhibits the aging effects of cracking and loss of material. Internal surfaces of carbon steel components exposed to treated water are subject to cracking and loss of material. Carbon steel exposed to sheltered, yard, underground, or fuel oil internal or external environments exhibit the aging effect of loss of material. Carbon steel exposed to ventilation or oil environments have no aging effects identified. Copper components exposed to an internal environment of treated water are subject to loss of material. Copper components exposed to ventilation or sheltered environments have no aging effects identified. Brass components exposed to an internal environment of treated water are subject to loss of material and cracking. Exposure of brass components to a sheltered environment is not subject to any aging effects. Cast iron exposed to internal or external environments of treated water or sheltered exhibits aging effect of loss of material. Aluminum exposed to ventilation or sheltered environments have no aging effect identified. Bronze components exposed to fuel oil environments demonstrate the aging effect of loss of material, while exposure of bronze to the sheltered environments has no aging effect identified. Wrought iron exposed to internal or external environments of fuel oil or sheltered environments exhibit the aging effect of loss of material. Glass or acrylic components exposed to fuel oil, ventilation, or sheltered environments exhibit no aging effects.

3.3.35.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the standby shutdown diesel system:

- Inspection Program for Civil Engineering Structures and Components
- Chemistry Control Program
- Preventive Maintenance Activities - Condenser Circulating Water System Internal Coatings Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the standby shutdown diesel system will be adequately managed by these aging management programs during the period of extended operation.

3.3.35.2 Staff Evaluation

The applicant described its AMR of the standby shutdown diesel system for license renewal in two separate sections of its LRA: Section 2.3.3.35 and Table 3.3-44, pages 3.3-247 to 255. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the standby shutdown diesel system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.35.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.35 and Table 3.3-44, pages 3.3-247 to 255, of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3-5, additional information pertaining to Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator, Exhaust Sub-System." This table indicated that components are subject to an internal environment of ventilation, which is defined as ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy. CN-1560-1.0, CN-1560-20, MCFD-1560-01.00, MCFD-1560-02.00, and MCFD-1614-4, "Flow Diagrams for Standby Shutdown Diesel System," do not include equipment to condition the intake air or the exhaust air for the diesels to provide a ventilation internal environment. Typically, these components are subject to a sheltered internal environment. The applicant was requested to provide justification for classifying the internal environment for these components as "ventilation." A similar question was asked about the diesel generator air intake and exhaust system components listed in Table 3.3-14 (refer to Section 3.3.11.2.1 of this SER).

In its response dated, March 15, 2002, the applicant stated that the staff is correct that these components are subject to a sheltered internal environment. Duke's aging management review conservatively evaluated environments such as tanks and piping that are open to atmosphere as a ventilation environment. Although the tanks and piping are open to sheltered environments, they would not experience significant air exchange and thus higher humidity and condensation could be present. The ventilation environment aging effect details account for the potential condensation, whereas the sheltered environment aging effect details do not. Loss of material and cracking due to alternate wetting and drying that concentrates contaminants are two aging effects considered plausible in a ventilation environment, but are not considered in sheltered environments. Loss of material due to selective leaching is another aging effect considered plausible in a ventilation environment, but is not considered in sheltered environments. Therefore, for conservatism, Duke chose to evaluate these component configurations using the ventilation environment aging management review details. The designation in the LRA table reflects this decision.

In electronic correspondence dated May 2, 2002, the staff requested the applicant to provide additional justification for claiming, in Table 3.3-44, that carbon steel external components are subject to sheltered environments while the internal environment is ventilation. The sheltered environment is subject to the aging effect of loss of material and managed by the "Inspection Program for Civil Engineering Structures and Components." The staff considered this to be in conflict with Duke's response that loss of material in sheltered environments is not considered an aging effect. The applicant was requested to clarify or justify how an "uncontrolled" sheltered environment is less conservative than a "controlled" ventilation environment and causes no aging effects or revise the aging effects and AMPs listed in Table 3.3-44 to be consistent with other sheltered environments listed in the tables. The staff further noted that its fundamental concern was that, for the diesel engine exhaust systems (which include no equipment [coolers or dryers] for controlling air quality), the internal environments are "sheltered," not "ventilation," and that the aging effects associated with the sheltered environment must be addressed for these internal surfaces.

In electronic correspondence dated May 10, 2002 (ML021440236), the applicant replied as follows:

> For Duke, a sheltered environment is an external environment for components inside a structure that may or may not be maintained by a ventilation system but are protected from the natural elements. Components in a sheltered environment could be wet from condensation or leakage that could promote aggressive corrosion, that left unmanaged, could result in a loss of the component intended function(s) during the period of extended operation. As such, the Inspection Program for Civil Engineering Structures and Components is credited to manage the aging effects on the external surfaces of components located in a sheltered environment.
>
> For components with an internal air environment open to the sheltered environment or yard environment (as is the case with the diesel exhaust), Duke classified the environment as a ventilation environment. Duke conservatively chose the ventilation environment because more aging mechanisms leading to aging effects are plausible and must be considered than in a sheltered environment. In our initial response to RAI 3.3-5, Duke tried to show that aging effects from some mechanisms are not plausible in a sheltered environment but could occur in a

> ventilation environment. Duke was providing examples to support our conservative position which we believe does not say that loss of material in a sheltered environment is not an aging effect.
>
> Duke evaluated the internal environment of the exhaust systems as a ventilation environment. The diesels operate periodically for short periods of time for testing but are primarily in standby. The internal environment is characterized as a warm, dry environment free from leaks and condensation. This environment does not preclude loss of material but does not promote the aggressive corrosion that left unmanaged would result in a loss of the component intended function(s) of the exhaust system components. Therefore, no aging effects requiring management during the period of extended operation were identified.

By letter dated July 9, 2002, the staff received this information from the applicant in official correspondence. The applicant confirmed that the internal environment is warm, dry, and free from leaks and condensation. Since this environment does not promote the aggressive corrosion that would result in a loss of the component intended function(s) of the exhaust system components, this issue is resolved.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.44-1, additional information pertaining to Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator, Exhaust Sub-System." This table does not list an internal environment, which has the potential for exposure of components to hot diesel engine exhaust gasses containing moisture and particulates. The applicant was requested to identify where in the LRA the AMR results are for steel components exposed to a hot diesel exhaust environment that have the potential for experiencing loss of material from general, pitting, and crevice corrosion, or to provide a justification for excluding this environment and aging effects from Table 3.3-44 and an AMR.

In its response dated March 15, 2002, the applicant stated that the results of the aging management review for the internal surfaces of the standby shutdown diesel generator, exhaust sub-system are presented in Table 3.3-44 of the LRA. The diesel generators are normally in standby and are operated periodically for a short period of time for surveillance testing. During diesel operation, the exhaust portion of this system will be exposed to hot gasses containing moisture and particulates. Exposure duration of the exhaust components to the hot gasses containing moisture and particulates is insignificant when compared to the exposure time of these components to the cool, ventilation environment. As a result, the internal environment of hot gasses containing moisture and particulates was not considered in the aging management review to identify the aging effects requiring management. Therefore, Table 3.3-44 listed ventilation as the internal environment. Since the components are used only during start-up of the diesel generator, the staff agrees that ventilation is the normal internal environment.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.44-2, additional information pertaining to Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator, Fuel Oil Sub-System." This table indicates that the shutdown diesel generator fuel oil valve bodies, fuel oil (duplex filters, Catawba only, on page 3.3-254) has a "PB," or pressure boundary, component function. This component also provides filtration of process fluids so that downstream equipment and/or environments are protected. The applicant was requested to explain why this component does not have a "FI," of filtration, component function as defined in the notes section for other AMR tables, or correct the component functions for filters listed in Table 3.3-44.

In its response dated March 15, 2002, the applicant stated that the Table 3.3-44 entry "Valve Bodies, Fuel Oil (duplex filters) (Catawba only)" pertains to the valves associated with the duplex filter assembly, not the filter itself. Although not necessary, the valves were differentiated because they were the only valves in the system with the given material/environment combination. The duplex filter is addressed in the entry on page 3.3-249, "Filter, Duplex (mounting head)," of the LRA. The mounting head is the only passive, long-lived portion of the duplex filter. The staff's evaluation of the applicant's treatment of filters is documented in Section 2.1.3.2.1 of this SER. Since the applicant clarified that the PB function is provided by valves associated with the duplex filter assembly, and that the filter is not subject to an AMR since it is replaced during periodic diesel engine maintenance, the staff finds that its response acceptable. The applicant addressed filters on page 2.1.2.1.2 of its LRA; the staff's evaluation of the applicant's treatment of filters is provided in Section 2.1.3.2.1 of this SER.

In its April 15, 2002, response to RAI 2.3.3.35-5 (see Section 2.3.3.35.2 of this SER), the applicant provided the following AMR results for carbon steel pipe (tubing) and pump casings to supplement the information provided in Table 3.3-44:

Component Type	**Component Function**	**Material**	**Internal Environment** / **External Environment**	**Aging Effects**	**Aging Management Programs and Activity**
Pipe	PB	CS	Treated Water	Cracking (Note 3)	Chemistry Control Program
				Loss of Material	Chemistry Control Program
			Sheltered	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Pump Casing (cooling water)	PB	CS	Treated Water	Cracking (Note 3)	Chemistry Control Program
				Loss of Material	Chemistry Control Program
			Sheltered	Loss of Material	Inspection Program for Civil Engineering Structures and Components

The aging effects that result from contact of the standby shutdown diesel system SSCs to the environments described in the applicant's response to RAI 2.3.3.35-5 and Section 2.3.3.35 and Table 3.3-44, pages 3.3-247 through 3.3-255, of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.35.2.2 Aging Management Programs

Section 2.3.3.35 and Table 3.3-44, pages 3.3-247 to 255, of the LRA states that the following aging management programs are credited for managing the aging effects in the standby shutdown diesel system.

- Inspection Program for Civil Engineering Structures and Components
- Chemistry Control Program
- Preventive Maintenance Activities - Condenser Circulating Water System Internal Coatings Inspection

The Preventive Maintenance Activities - Condenser Circulating Water System Internal Coatings Inspection Program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and, with the exception of open item 3.0.3.13.2-1 for the Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection program (see Section 3.0.3.13.2 of this SER), found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

The staff reviewed the information in Section 2.3.3.35; Table 3.3-44, pages 3.3-247 to 255; and Section B.3.6, "Chemistry Control Program," of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3-6, additional information pertaining to Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator." This table indicates that the cooling water and jacket water engine radiator heat exchanger has a function of HT that is managed by the Chemistry Control Program. Heat transfer monitoring is not identified as a capability of the Chemistry Control Program, as defined in Appendix B, Section B.3.6. The applicant was requested to explain how the Chemistry Control Program monitors the heat transfer function.

In its response dated March 15, 2002, the applicant stated that for the heat exchangers in the standby shutdown diesel generator, cooling water and jacket water heating sub-system, Duke determined that the component intended functions that must be maintained for the period of extended operation for these heat exchangers are heat transfer and pressure boundary. For heat exchangers, fouling is the only aging effect that will result in a loss of the intended function of heat transfer. Duke determined during the aging management review that fouling would not occur for these closed loop heat exchangers because there is constant flow through the heat exchangers, and the treated water in the system is filtered to remove particles. Therefore, no aging management program is required. Loss of material is an aging effect that could result in a loss of the intended function of pressure boundary for these heat exchangers during the period of extended operation. The Chemistry Control Program is credited as the aging management program to manage loss of material during the period of extended operation.

The staff agrees that the Chemistry Control Program will manage the loss of material because ir provides for chemistry controls and the presence of corrosion inhibitors in the treated water to which the heat exchanger is exposed. The staff does not agree with the applicant's conclusion that fouling will not occur in the heat exchanger because of the constant flow through the heat exchanger. The staff recognizes that sufficient flow through the heat exchanger may prevent areas of stagnation in which fouling may occur. However, the applicant has not substantiated their conclusion with any operating experience, such as maintenance and surveillance results, that reflect the success of this activity in preventing fouling. With respect to the filtering of the treated water to remove particles, the staff recognizes that particulates are removed through a filtering process. However, the applicant does not list or credit a periodic surveillance of the filter to ensure that the entrained particles do not create a high differential pressure and adversely affect flow through the heat exchanger. Therefore, this issue is characterized as open item 3.3.35.2-1.

Based on its review of LRA Table 3.3-44, with the exception of open items 3.3.35.2-1 and 3.0.3.13.2-1, the staff concludes that the above identified AMPs will effectively manage the aging effects of the standby shutdown diesel system and that there is reasonable assurance that the intended functions of the standby shutdown diesel system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.35.3 Conclusions

The staff reviewed the information in the applicant's response to RAI 2.3.3.35-5 and Section 2.3.3.35 and Table 3.3-44 of the LRA. On the basis of its review, with the exception of open items 3.3.35.2-1 and 3.0.3.13.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the standby shutdown diesel system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.36 Turbine Building Sump Pump System (Catawba Nuclear Station Only)

3.3.36.1 Technical Information in the Application

No portion of the McGuire turbine building sump pump system is within the scope of license renewal. Only the Duke Class F portions of the turbine building sump pump system are in scope at Catawba. McGuire has no Class F components in the turbine building sump pump system.

The Catawba turbine building sump pump system serves as a collection point for the contents of liquid radwaste system sumps when the contents of the sumps contain less than predetermined levels of radiation, as sensed by radiation monitors in the discharge lines. The turbine building sump pump system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this systems are within the scope of license renewal per §54.4(a)(2).

3.3.36.1.1 Aging Effects

Components of the turbine building sump pump system are described in Section 2.3.3.36 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-45, page 3.3-256, of the LRA lists individual components of the system including pipe. Carbon steel components exposed to raw water (internal environment) and a sheltered external environment are subject to loss of material aging effects.

3.3.36.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the turbine building sump pump system:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Sump Pump Systems Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the turbine building sump pump system will be adequately managed by these aging management programs during the period of extended operation.

3.3.36.2 Staff Evaluation

The applicant described its AMR of the turbine building sump pump system for license renewal in two separate sections of its LRA: Section 2.3.3.36 and Table 3.3-45, page 3.3-256. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the turbine building sump pump system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.36.2.1 Aging Effects

The aging effects that result from contact of the turbine building sump pump system SSCs to the environments described in Section 2.3.3.36 and Table 3.3-45, page 3.3-256, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.36.2.2 Aging Management Programs

Section 2.3.3.36 and Table 3.3-45, page 3.3-256, of the LRA states that the following aging management programs are credited for managing the aging effects in the turbine building sump pump system.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Sump Pump Systems Inspection

The Fluid Leak Management Program, Inspection Program for Civil Engineering Structures and Components, and Sump Pump Systems Inspection Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-45, the staff concludes that the above identified AMPs will effectively manage the aging effects of the turbine building sump pump system and that there is reasonable assurance that the intended functions of the turbine building sump pump system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.36.3 Conclusions

The staff reviewed the information in Section 2.3.3.36 and Table 3.3-45, page 3.3-256, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the turbine building sump pump system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.37 Turbine Building Ventilation System (McGuire Nuclear Station Only)

3.3.37.1 Technical Information in the Application

The Catawba turbine building ventilation system SCs are not within the scope of license renewal. The Catawba miscellaneous structures ventilation system that provides SSF HVAC is addressed in Section 2.3.3.25.

The McGuire turbine building ventilation system includes the HVAC system in the standby shutdown facility (SSF), of which a portion is entitled standby shutdown facility HVAC system. The SSF HVAC portion of the turbine building ventilation system provides the heating, ventilation and air conditioning requirements for the SSF and consists of air conditioning and ventilation subsystems. The McGuire UFSAR Section 9.4.4, Turbine Building, provides additional information concerning the SSF HVAC portion of the McGuire turbine building ventilation system.

Components of the turbine building ventilation system are described in Section 2.3.3.37 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-46, page 3.3-257, of the LRA lists individual components of the system including air handling units, ductwork, flexible connectors, and plenum sections. Galvanized steel and neoprene components are identified as being subject to the internal environment of ventilation and the external sheltered environment with no aging effects identified.

The applicant stated that the SCs in this system are not subject to any aging effects. Therefore, no AMPs are necessary in the turbine building ventilation system.

3.3.37.2 Staff Evaluation

The applicant described its AMR of the turbine building ventilation system for license renewal in two separate sections of its LRA: Section 2.3.3.37 and Table 3.3-46, page 3.3-257. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the turbine building ventilation system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.37.2.1 Aging Effects

The applicant's conclusion that no aging effects result from contact of the miscellaneous structures ventilation system SSCs to the environments listed in Section 2.3.3.25 and Table 3.3-33, page 3.3-209, is consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff agrees with the applicant that there are no aging effects for the combination of materials and environments listed.

3.3.37.2.2 Aging Management Programs

There are no aging effects identified in this system. Therefore, no AMPs are required in the turbine building ventilation system.

3.3.37.3 Conclusions

The staff reviewed the information in Section 2.3.3.37 and Table 3.3-46, page 3.3-257, of the LRA. On the basis of its review, the staff concludes that the SCs in the turbine building ventilation system are not subject to any aging effects. Therefore, no AMPs are required in the turbine building ventilation system..

3.3.38 Waste Gas System

3.3.38.1 Technical Information in the Application

The McGuire waste gas system removes fission gases from radioactive contaminated fluids and contains these gases in holdup tanks indefinitely. Storage and subsequent decay of these gases eliminates the need for regularly scheduled discharge of these radioactive gases from the system into the atmosphere during normal plant operation. The McGuire UFSAR Section 11.3, Waste Gas System, provides additional information concerning the McGuire waste gas system.

The Catawba waste gas system removes fission product gases from radioactive fluids and contains these gases for a time sufficient to allow ample decay of the nuclides prior to release in accordance with applicable NRC regulations. The system is designed to control and minimize releases of radioactive effluent to the environment by reducing the fission product gas concentration in the reactor coolant, which may escape during maintenance operations or from equipment leaks. The Catawba UFSAR Section 11.3, Waste Gas System, provides additional information concerning the Catawba waste gas system.

3.3.38.1.1 Aging Effects

Components of the waste gas system are described in Section 2.3.3.38 of the submittal as being within the scope of license renewal, and subject to AMR. Table 3.3-47, pages 3.3-258 to 263, of the LRA lists individual components of the system including flow meters, hydrogen recombiners, hydrogen recombiner heat exchangers, hydrogen recombiner heaters, hydrogen recombiner separators, safety discs, orifices, pipe, strainers, tubing, heat exchangers, decay tanks, and valve bodies. Stainless steel components are identified as being subject to the internal or external environments of gas or sheltered with no aging effects identified. An internal or external environment of treated water causes the aging effects loss of material, fouling, and cracking in stainless steel components. Internal or external surfaces of carbon steel components exposed to treated water, sheltered, or gas environments experience the aging effect of loss of material and cracking. Brass components exposed to an internal or external environment of treated water are subject to loss of material.

3.3.38.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects to the waste gas system:

- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- Waste Gas System Inspection
- Chemistry Control Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effect of aging associated with the components of the waste gas system will be adequately managed by these aging management programs during the period of extended operation.

3.3.38.2 Staff Evaluation

The applicant described its AMR of the waste gas system for license renewal in two separate sections of its LRA: Section 2.3.3.38 and Table 3.3-47, pages 3.3-258 to 263. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the waste gas system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.38.2.1 Aging Effects

The staff reviewed the information in Section 2.3.3.38 and Tables 3.3-47, pages 3.3-258 to 263, of the LRA. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3.47-1, additional information pertaining to Table 3.3-47, "Aging Management Review Results - Waste Gas System." This table identifies an internal environment described as gas. The definition for air-gas environments identified at the beginning of the tables does not adequately describe the gas environment found in the waste gas system. The waste gas system contains mixed radioactive fission gases (e.g., Kr, Xe, I, Cs) in addition to those listed in the air-gas definition. The applicant was requested to clarify if the air-gas environment described at the beginning of the tables includes fission gases or add a new definition for the gas environment found in the waste gas system.

In its response dated March 15, 2002, the applicant stated that the waste gas system continuously circulates nitrogen around the system loop. Hydrogen containing oxygen and fission product gasses is vented into the waste gas system from the volume control tanks of the chemical and volume control system. Additional oxygen is added immediately upstream of the recombiners to reduce the hydrogen concentrations in the waste gas stream to residual levels. As a result, the environment is compressed nitrogen gas containing fission product gasses and is consistent with the definition of a gas environment on page 3.3-3 of the LRA. Since the response clarifies the definition of the air-gas environment as nitrogen gas containing fission product gasses, the staff finds its response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.47-2, additional information pertaining to Table 3.3-47, "Aging Management Review Results - Waste Gas System." This table indicates that, for the Catawba plant, the orifices for waste gas compressor seal and make-up have a “PB,” or pressure boundary component function. Typically, orifices also provide the function listed as "TH" (provide throttling so that sufficient flow and/or sufficient pressure is delivered, provide backpressure, provide pressure reduction, or provide differential pressure). The applicant was requested to explain why orifices in the Catawba waste gas system do not provide the function "TH," or correct the component functions for orifices listed in Table 3.3-47.

In its response dated March 15, 2002, the applicant stated that the waste gas compressor is a non-safety-related component that is not required to operate in support of any function related to §54.4(a)(1) of the Rule. The components associated with the compressor are only required to maintain pressure boundary integrity in support of §54.4(a)(1)(iii). Therefore, throttling is not a license renewal intended function of the seal and make-up orifices. Since the intended function for the orifices is to maintain pressure boundary integrity only, and “TH” is not a license renewal intended function, the staff finds that the applicant's response clarifies and satisfactorily resolves this item.

In its April 15, 2002, response to RAI 2.3.3.38-1 (see Section 2.3.3.38.2 of this SER), the applicant provided the following AMR results for the waste gas separators:

Component Type	**Component Function**	**Material**	**Internal Environment** **External Environment**	**Aging Effect**	**Aging Management Programs and Activities**
Waste Gas Separators	PB	Synthetic Rubber*	Gas Sheltered	None Identified None Identified	None Required None Required
Waste Gas Separators	PB	SS	Treated Water (unmonitored) Sheltered	Cracking Loss of Material None Identified	Waste Gas System Inspection Waste Gas System Inspection None Required

The aging effects that result from contact of the waste gas system SSCs to the environments described in the applicant’s response to RAI 2.3.3.38-1 and Section 2.3.3.38 and Table 3.3-47, pages 3.3-258 through 3.3-263, of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.3.38.2.2 Aging Management Programs

Section 2.3.3.38 and Table 3.3-47, pages 3.3-258 to 263, of the LRA states that the following aging management programs are credited for managing the aging effects in the waste gas system.

- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- Waste Gas System Inspection
- Chemistry Control Program

The Fluid Leak Management Program, Galvanic Susceptibility Inspection Program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

During its review of the information in Section 2.3.3.38 and Tables 3.3-47, pages 3.3-258 to 263, of the LRA, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3-6, additional information pertaining to Table 3.3-47, "Aging Management Review Results - Waste Gas System," identifies the hydrogen recombiner heat exchanger tubes as having a function of heat transfer. Heat transfer monitoring is not identified as a capability of the Chemistry Control Program, as defined in Appendix B, Section B.3.6. The applicant was requested to explain how the Chemistry Control Program monitors the heat transfer function.

In its response dated March 15, 2002, the applicant stated that for the hydrogen recombiner heat exchangers in the waste gas system found in Table 3.3-47 of the LRA, fouling was identified as an aging effect requiring management during the period of extended operation. The Chemistry Control Program is credited with managing this aging effect. The hydrogen recombiner heat exchangers are cooled by the component cooling system and could foul due to silting from corrosion product buildup. The component cooling system is a closed cooling water system that contains corrosion inhibitors to mitigate loss of material that would generate corrosion products that could be transported to and foul the hydrogen recombiner heat exchangers. The Chemistry Control Program monitors and controls the corrosion inhibitors to mitigate the generation of corrosion products, which would mitigate fouling of the hydrogen recombiner heat exchangers.

The staff finds that the applicant's response clarifies and satisfactorily resolves this item pertaining to the Chemistry Control Program. The staff's evaluation of the Waste Gas Systems Inspection Program follows.

<u>Waste Gas Systems Inspection Program</u>

The applicant describes its Waste Gas System Inspection program in Section B.3.36 of the LRA. The applicant credits this program with managing the potential aging of liquid waste systems structures and components that are within the scope of license renewal. The inspection activity monitors for loss of material and cracking. The staff reviewed Section B.3.22 of the LRA to determine whether the applicant had demonstrated that the liquid waste system inspection activities will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

In Section B.3.22 of the LRA, the applicant states that the purpose of the Waste Gas System Inspection program is to provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of equipment and components within the scope of 10 CFR Part 54 will be maintained consistent with the CLB for the period of extended operation. This program is credited with managing any loss of material and cracking of system components within the scope of license renewal that are exposed to unmonitored borated, treated, and/or raw water environments. The program is credited with managing the potential aging of the following systems:

- Component cooling system (McGuire only) - stainless steel waste evaporator package exposed to an unmonitored treated water environment of the liquid waste recycle system;
- Liquid waste recycle system (McGuire only) - stainless steel components exposed to an unmonitored borated water environment;
- Liquid radwaste system (Catawba only) - stainless steel components exposed to an unmonitored borated water, unmonitored treated water, or a raw water environment; carbon steel and cast iron components exposed to a raw water environment.

The Liquid Waste System Inspection detects aging effects through a combination of volumetric and/or visual examination. For the McGuire component cooling system, one of the four heat exchangers associated with the waste evaporator will be inspected. For the McGuire liquid waste recycle system and the Catawba liquid radwaste system, a combination of volumetric and visual examination will be performed for sample population of components chosen based on conditions likely to cause a more corrosive environment. This is a one-time inspection activity. If evaluation of the inspection findings indicates that continuation of the aging effects will cause a loss of intended function(s), additional inspection will be performed and/or corrective action will be taken.

The applicant concluded that implementation of this program will adequately verify that the components will continue to perform their intended function(s) for the period of extended operation.

The staff’s evaluation of the Waste Gas System Inspection program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures. The staff’s evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] Section B.3.22 of the LRA identifies the structures and components that credit the liquid waste system inspection activities for managing the aging effects of loss of material and cracking. The program scope includes the following systems:

- Component cooling system (McGuire only) - stainless steel waste evaporator package exposed to an unmonitored treated water environment of the liquid waste recycle system;
- Liquid waste recycle system (McGuire only) - stainless steel components exposed to an unmonitored borated water environment;
- Liquid radwaste system (Catawba only) - stainless steel components exposed to an unmonitored borated water, unmonitored treated water, or a raw water environment; carbon steel and cast iron components exposed to a raw water environment.

The program covers the in-scope structures and components that are exposed to the liquid waste system environments. Therefore, the scope of the program is acceptable to the staff.

[Preventive or Mitigative Actions] There are no preventive actions taken as part of this program, and the staff did not identify the need for any preventive actions.

[Parameters Monitored or Inspected] Section B.3.22 of the LRA identifies loss of material and cracking as the parameters that can be detected by volumetric and/or visual inspection. Because these inspection techniques can be used to identify the degraded conditions noted by the applicant, such inspections of the structures and components are acceptable to the staff.

[Detection of Aging Effects] Section B.3.22 of the LRA states that volumetric and/or visual inspection will detect loss of material and cracking for the structures and components. The use of volumetric and/or visual inspection is considered by the staff to be a reasonable means of detecting these aging effects before the loss of intended function, and is consistent with NRC and industry guidance. Therefore, the staff finds this acceptable.

[Monitoring and Trending] Section B.3.22 of the LRA states that the one-time inspections will be performed as described above. By letter dated January 28, 2002, the staff requested, in RAI B.3.22-1, additional information related to the criteria that will be used to select the areas that are inspected. In its response dated March 15, 2002, the applicant stated that the selection criteria will include such items as component orientation, operating temperature, proximity to hot equipment, and previous operating experience. The staff finds the applicant's response reasonable and acceptable.

Section B.3.22 of the LRA states that no actions are taken as part of the program to trend the inspection results. If evaluation of the inspection findings indicates that continuation of the aging effects will cause a loss of intended function(s), additional inspection will be performed and/or corrective action will be taken. Since corrective actions and confirmatory actions, as needed, are implemented in accordance with the corrective action program, the staff finds this acceptable.

[Acceptance Criteria] Section B.3.22 of the LRA states that the acceptance criterion for the inspection is no unacceptable loss of material that could result in the loss of the component intended function(s), as determined by engineering evaluation. By letter dated January 28, 2002, the staff asked, in RAI B.3.22-2, the applicant to describe the criteria for assessing the severity of observed degradations and the need for corrective actions. In its response dated March 15, 2002, the applicant stated that the criteria would be developed at the time of the inspection. Criteria such as the ASME Code, results from additional inspections, and operating experience may be used to assess the severity of the degradation and the need for corrective action. The staff finds the applicant's response reasonable and acceptable.

[Operating Experience] Section B.3.22 of the LRA states that the Liquid Waste System Inspection is a one-time inspection for which there is no operating experience. The staff finds this reasonable and acceptable.

FSAR Supplement: The staff reviewed Appendix A of the LRA, Section 18.2.18 the FSAR Supplement for McGuire, and Section 18.2.17 of the UFSAR for Catawba. The staff finds that the summary description is consistent with the LRA and is acceptable.

In conclusion, the staff has reviewed the information provided in the applicant's response to RAI 2.3.3.38-1, Section B.3.22 of the LRA, the summary description of the Liquid Waste System Inspection in Appendix A of the LRA, and the applicant's March 15, 2002, response to the staff's RAIs. On the basis of its review and the above evaluation, the staff finds that the Liquid Waste System Inspection program will adequately manage the aging effects such that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on its review of Table 3.3-47 and Appendix B of the LRA, the staff concludes that the above identified AMPs will effectively manage the aging effects of the waste gas system and that there is reasonable assurance that the intended functions of the waste gas system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.38.3 Conclusions

The staff reviewed the information in the applicant's response to RAI 2.3.3.38-1 and Section 2.3.3.38 and Table 3.3-47 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the waste gas system will be adequately managed so that there is reasonable assurance that the system components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.39 Auxiliary Systems - General

3.3.39.1 Thermal Fatigue

The applicant did not identify cracking due to thermal fatigue as an aging effect requiring management in Section 3.3 for the auxiliary system components. However, the applicant identified thermal fatigue for piping systems designed to the requirements of ANSI B31.1 or ASME Section III, Subsection NC, or Subsection ND as a time limited aging analysis (TLAA) in Section 4.3.2 of the LRA. The staff's evaluation of that TLAA is in Section 4.3 of this SER, and aging effect due to thermal fatigue, as it applies to auxiliary system components, will not be discussed further in this section of the SER.

3.3.39.2 Scoping Issues Related to Aging Management Programs for Auxiliary Systems

The scoping requirements of 10 CFR 54.4(a)(2) include all non-safety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1)(i), (ii), or (iii). By letter dated January 23, 2002, the staff requested additional information, per RAI 3.3-2, as to whether the scope of the auxiliary systems discussed in Section 3.3 of the LRA includes any seismic II over I SSCs as described in position C.2 of Regulatory Guide 1.29. In addition, the applicant was requested to clarify how the AMPs provided in tables of the LRA Section 3.3 apply to those seismic II over I piping systems to assure that plausible aging effects associated with those piping systems, if any, will be appropriately managed. The applicant responded to this RAI in a letter dated April 15, 2002 by referring to its response to RAIs 2.1-2.a and 2.1-2.b that provide information on scoping seismic II over I SSCs. The applicant’s response to RAI 2.1-2.a also provides a complete list of piping systems included within the scope of license renewal that fall into the category of seismic II over I SSCs. The staff’s evaluation of the applicant’s response to RAIs 2.1-2.a and 2.1-2.b concerning the scoping and screening methodology for identifying seismic II over I SSCs is in Section 2.1 of this SER, and will not be discussed further in this section of the SER. In addition, in its response to RAI 3.3-2, the applicant stated that the AMPs included in LRA Section 3.3 tables also apply to seismic II over I piping systems. The applicant further stated that Function 7 of Table 3.5-3 of the LRA is applicable for seismic II over I pipe supports. The aging effects of those pipe supports are managed by the AMP listed in the table for that entry.

Based on the above discussion, the staff finds the applicant’s response clarifies and satisfactorily resolves the concern documented in RAI 3.3-2. The applicant’s response ensures that plausible aging effects associated with seismic II over I SSCs as they apply to auxiliary systems will be appropriately managed and, therefore, is acceptable.

3.3.39.3 Ventilation Systems Flexible Connectors

Numerous ventilation systems included in Section 3.3 of the LRA do not list elastomer components associated with the ventilation systems. Normally, ventilation systems contain elastomer materials in duct seals, flexible collars between ducts and fans, rubber boots, etc. For some plant designs, elastomer components are used as vibration isolators to prevent transmission of vibration and dynamic loading to the rest of the system. The aging effects of concern for those elastomer components are hardening and loss of material.

By letter dated January 23, 2002, the staff requested, in RAI .3-1, the applicant to indicate where in the LRA the aging effects of hardening and loss of material to elastomer components, such as duct seals, flexible collars, rubber boots, etc., were addressed.

In its response dated April 15, 2002, the applicant acknowledged that flexible connectors were inadvertently omitted from the application for the auxiliary building, control area, diesel building, and fuel handling building or fuel handling area ventilation systems. Tables 3.3-1, 3.3-11, 3.3-13, and 3.3-28 were subsequently revised to include AMR results for these components. However, no aging effects were identified.

In electronic correspondence dated May 2, 2002, the staff requested the applicant to explain why no aging effects or AMP were identified for the elastomer components in sheltered environments in the revised tables provided on April 15, 2002.

In electronic correspondence dated May 10, 2002 (ML021440236), the applicant stated that the aging effects for loss of material and change in material properties (hardening) from exposure to ambient environmental conditions at the locations within the plant were evaluated. The results of this evaluation showed that the internal and external temperature and radiation levels at these flexible connector locations are well below those known to be an aging concern for the period of extended operation. No aging effects were, therefore, identified in the LRA. By letter from the applicant dated July 9, 2002, the staff received this explanation in official correspondence. Since the applicant explained that the internal and external environments do not pose an aging concern for the period of extended operation, the staff finds that no aging effects are expected. This issue is resolved.

3.3.39.4 Aging Management Review for Closure Bolting in Auxiliary Systems

Although the LRA provided AMR results for Class 1 bolting, it did not address bolting for Non-Class 1 components. By letter dated January 23, 2002, the staff requested, in RAI 3.2-1, additional information that pertains to tables in Sections 3.2, 3.3, and 3.4 of the LRA that list closure bolting as components subject to AMR. The staff stated that since closure bolting is exposed to air, moisture, and leaking fluid (boric acid) environments, it is subject to the aging effect of loss of material and crack initiation and growth. Tables in Sections 3.2, 3.3 and 3.4 do not address these aging effects for closure bolting in these systems. The staff requested the applicant to identify the AMR results for closure bolting, or to provide a justification for excluding closure bolting from an AMR, the results of which are documented in the referenced tables of the LRA.

3.3.39.4.1 Aging Effects

The applicant indicated that non-class 1 mechanical components within the scope of license renewal contain bolted closures that are necessary for the pressure boundary of the component. Examples of these bolted closures are valve bonnet to body closures, pump cover to casing closures, heat exchanger manway and end-bell closures and piping flange sets. The bolted closure is comprised of two mating surfaces, a gasket, and a fastener set of studs or bolts and nuts. By themselves, the mating set, gasket, and fastener set have no component intended function. Together, the bolted closure forms an integral part of the pressure-retaining boundary of the component. Gaskets are not relied upon for pressure boundary of the bolted closure in accordance with the design codes and are not subject to an aging management review.

Bolted closures are exposed to two environments. The mating surfaces are exposed internally to the process fluid while the external surfaces and the fastener set are exposed to the ambient environment where the bolted closures are located. Aging effects for external and internal surfaces of the mating set of bolted closures are the same as other components in the system of the same material and exposed to the same environment. Programs for the system (i.e., chemistry in a treated water system and fluid leak management program) containing the bolted closure are applicable to the mating set and are not discussed here further.

The aging effects for the fastener set of non-Class 1 bolted closures are loss of material of carbon and low alloy steel and cracking of carbon, low alloy, and stainless steels. Loss of material of the fastener set of the bolted closure may occur as a result of fluid leakage, use of an improper lubricant during assembly, or exposure to the ambient environment. Cracking of the fastener set of bolted closures may occur as a result of improper material selection, improper torquing during assembly, use of an improper lubricant, fluid leakage, or exposure to the ambient environment. Of these aging effects, Duke determined the following are the aging effects requiring management for carbon and low alloy steel fastener sets:

- loss of material of the fastener set due to boric acid exposure;
- loss of material of the fastener set in systems with operating temperatures below ambient conditions that result in condensation; and
- loss of material of the fastener set in the yard environment that are repeatedly wetted and dried from exposure to the elements.

The applicant stated that no aging effects requiring management were identified for the stainless steel fastener set of bolted closures.

On the basis of its review of the RAI response pertaining to Non-Class 1 bolting, the staff finds that all applicable aging effects were identified, and the aging effects identified are appropriate for the combination of materials and environments listed.

3.3.39.4.2 Aging Management Programs

The applicant indicated that the Fluid Leak Management Program will manage loss of material of non-Class 1 bolted closures in the Reactor and Auxiliary Buildings due to leakage from systems containing boric acid. No systems containing boric acid are located outside these two buildings. The Fluid Leak Management Program is described in Appendix B, Section B.3.15 of the LRA for McGuire and Catawba.

The Inspection Program for Civil Engineering Structures and Components will manage loss of material of non-Class 1 bolted closures in systems with operating temperatures below the surrounding ambient environment that are wet with condensation. In addition, this program will also manage loss of material of non-Class 1 bolted closures located in the yard that are repeatedly wetted and dried from exposure to the elements. The Inspection Program for Civil Engineering Structures and Components is described in Appendix B, Section B.3.21 of the LRA for McGuire and Catawba.

The Fluid Leak Management program and the Inspection Program for Civil Engineering Structures and considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for Non-Class 1 closure bolting. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

3.3.39.4.3 Conclusions

Based on the above discussion, the staff finds that the applicant's response clarifies and satisfactorily resolves this issue concerning the closure bolting in mechanical systems as described in RAI 3.2-1. The staff concludes that the applicant has demonstrated that the aging effects associated with Non-Class 1 closure bolts will be adequately managed so there is reasonable assurance that these components will perform their intended functions consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4 Steam and Power Conversion Systems

The applicant described its AMR of the steam and power conversion systems (SPCSs) for license renewal in Sections 2.3.4, "Steam and Power Conversion Systems," and 3.4, "Aging Management of Steam and Power Conversion Systems," of its LRA. The staff has reviewed these sections of the application to determine whether the applicant has provided adequate information to meet the requirements of 10 CFR 54.21(a)(3) for managing the aging effects of the SPCSs for license renewal.

3.4.1 Auxiliary Feedwater System

The auxiliary feedwater system is described in Section 2.3.4.1, "Auxiliary Feedwater System," of the LRA. The applicant provided the results of its AMR of the auxiliary feedwater system for license renewal in Table 3.4-1 of the LRA.

3.4.1.1 Technical Information in the Application

The auxiliary feedwater system is a nuclear safety-related system that serves as a backup to the feedwater system to ensure the safety of the plant and protection of equipment. The auxiliary feedwater system is essential to prevent an unacceptable decrease in the steam generator water levels; to reverse the rise in reactor coolant temperature; to prevent the pressurizer from filling to a water solid condition; and to establish stable hot standby conditions. The auxiliary feedwater system can be used during an emergency as well as during normal startup and shutdown operations. The auxiliary feedwater system is essentially the same and provides the same functions at both McGuire and Catawba. Section 10.4.10 of the McGuire UFSAR and Section 10.4.9 of the Catawba UFSAR provide additional information on the auxiliary feedwater system. The mechanical components subject to aging management review, their intended functions, and materials of construction for the auxiliary feedwater system are listed in Table 3.4-1 of the LRA.

3.4.1.1.1 Aging Effects

The materials of construction for the auxiliary feedwater system, structures, and components are carbon steel and stainless steel.

A description of internal environments for the auxiliary feedwater system is provided in Table 3.4-1 of the LRA. The auxiliary feedwater system components are exposed to the following environments: treated water and lubricating or fuel oil.

External surfaces of the structures and components in the auxiliary feedwater system are exposed to sheltered ambient air, oil, and reactor building environments, which are discussed in Section 3.4.1 of the LRA.

The applicant identified the following aging effects associated with the auxiliary feedwater system, structures, and components that require management:

- loss of material, cracking and fouling of stainless steel components in a treated water environment
- loss of material from carbon steel components in reactor building, sheltered air and treated water environments

3.4.1.1.2 Aging Management Programs

The applicant identified the following aging management programs to manage the aging effects for the auxiliary feedwater system components:

- chemistry control program
- flow accelerated corrosion program (applicable to Catawba only)
- fluid leak management program
- inspection program for civil engineering structures and components

A description of these AMPs, along with the applicant's discussion of how that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of the LRA: Section B.3.6, "Chemistry Control Program;" Section B.3.14, "Flow Accelerated Corrosion Program;" Section B.3.15, "Fluid Leak Management Program;" and Section B.3.21, "Inspection Program for Civil Engineering Structures and Components."

3.4.1.2 Staff Evaluation

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging on the auxiliary feedwater system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.1.2.1 Aging Effects

The aging effects that result from contact of the auxiliary feedwater system, structures, and components with the environments shown in Table 3.4-1 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.4.1.2.2 Aging Management Programs

Table 3.4-1 of the LRA states that the following aging management programs are credited for managing the aging effects of the auxiliary feedwater system components:

- chemistry control program
- flow accelerated corrosion program (applicable to Catawba only)
- fluid leak management program
- inspection program for civil engineering structures and components

The chemistry control program, flow accelerated corrosion program, fluid leak management program, and inspection program for civil engineering structures and components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. Although the applicant proposes to mitigate loss of material of the carbon steel piping components by chemistry control, the staff believes that the effectiveness of the mitigation should be verified by implementing a one-time inspection of the internal surfaces of these components. This is characterized as open item 3.4.1.2.2-1.

Based on its review of LRA Table 3.4-1, with the exception of open item 3.4.1.2.2-1, the staff concludes that the above identified AMPs will effectively manage the aging effects of the auxiliary feedwater system and that there is reasonable assurance that the intended functions of the auxiliary feedwater system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.1.3 Conclusion

The staff reviewed the information in Table 3.4-1, "Auxiliary Feedwater System." On the basis of its review, with the exception of open item 3.4.1.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the auxiliary feedwater system will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2 Auxiliary Steam System

The auxiliary steam system is described in Section 2.3.4.2, "Auxiliary Steam System" of the LRA. The applicant described the results of its AMR of the auxiliary steam system for license renewal in Table 3.4-2, "Aging Management Review Results - Auxiliary Steam System," of the LRA.

3.4.2.1 Technical Information in the Application

The auxiliary steam system provides steam to various plant equipment as required during all modes of plant operation, including condensate cleanup, startup, normal operation, and shutdown. The auxiliary steam system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. The mechanical components subject to AMR, their intended functions, and their materials of construction are listed in Table 3.4-2 of the LRA.

3.4.2.1.1 Aging Effects

The materials of construction for the auxiliary steam system, structures, and components are brass, carbon steel, copper and stainless steel. A description of internal and external environments for the auxiliary steam system is provided in Table 3.4-2 of the LRA. The auxiliary steam system components are internally exposed to treated water and steam environments. External surfaces of the structures and components in the auxiliary steam system are exposed to sheltered and yard environments, which are discussed in Section 3.4.1 of the LRA.

The applicant identified the following aging effects associated with the auxiliary steam system, structures, and components that require management:

- loss of material and cracking of brass and stainless steel components in treated water and steam environments
- loss of material from carbon steel, copper and brass components in sheltered air and treated water/steam environments

The LRA did not identify an aging effect for the stainless steel components exposed to sheltered environment for the auxiliary steam system.

3.4.2.1.2 Aging Management Programs

The applicant identified the following AMPs to manage aging effects for the auxiliary steam system components:

- chemistry control program
- flow accelerated corrosion program (applicable to Catawba only)
- fluid leak management program
- inspection program for civil engineering structures and components

A description of these AMPs, along with the applicant's discussion of how that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of the LRA: Section B.3.6, "Chemistry Control Program;" Section B.3.14, "Flow Accelerated Corrosion Program;" Section B.3.15, "Fluid Leak Management Program;" and Section B.3.21, "Inspection Program for Civil Engineering Structures and Components."

3.4.2.2 Staff Evaluation

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging on the auxiliary steam system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.2.2.1 Aging Effects

The aging effects that result from contact of the auxiliary steam system, structures, and components with the environments shown in Table 3.4-2 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.4.2.2.2 Aging Management Programs

Table 3.4-2 of the LRA states that the following AMPs are credited for managing the aging effects of loss of material and cracking for the auxiliary steam system components:

- chemistry control program
- flow accelerated corrosion program (applicable to Catawba only)
- fluid leak management program
- inspection program for civil engineering structures and components

The chemistry control program, flow accelerated corrosion program, fluid leak management program, and inspection program for civil engineering structures and components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-2, the staff concludes that the above identified AMPs will effectively manage the aging effects of the auxiliary steam system and that there is reasonable assurance that the intended functions of the auxiliary steam system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.3 Conclusion

The staff reviewed the information in Table 3.4-2, "Auxiliary Steam System." On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the auxiliary steam system will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.3 Condensate System

The condensate system is described in Section 2.3.4.3, "Condensate System" of the LRA. The applicant described the results of its AMR of the condensate system for license renewal in Table 3.4-3 of the LRA.

3.4.3.1 Technical Information in the Application

The condensate system provides water to various plant equipment as required during all modes of plant operation, including condensate cleanup, startup, normal operation, and shutdown. The condensate system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. The mechanical components for Catawba condensate system subject to aging management review, their intended functions, and materials of construction for the condensate system are listed in Table 3.4-3 of the LRA. No portion of the McGuire condensate system is within the scope of license renewal.

3.4.3.1.1 Aging Effects

The material of construction for the condensate system, structures, and components is carbon steel. A description of internal environments for the condensate system is provided in Table 3.4-3 of the LRA. The condensate system components are internally exposed to a treated water environment. External surfaces of the structures and components in the condensate system are exposed to the sheltered environment which is discussed in Section 3.4.1 of the LRA.

Loss of material in carbon steel components in sheltered environment was identified as the only aging effect associated with the condensate system, structures, and components that requires management.

3.4.3.1.2 Aging Management Programs

The applicant identified the following AMPs to manage the aging effect of loss of material for the condensate system components:

- chemistry control program
- fluid leak management program
- inspection program for civil engineering structures and components

A description of these AMPs, along with the applicant's discussion of how that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of the LRA: Section B.3.6, "Chemistry Control Program;" Section B.3.15, "Fluid Leak Management Program;" and Section B.3.21, "Inspection Program for Civil Engineering Structures and Components."

3.4.3.2 Staff Evaluation

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging on the condensate system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.3.2.1 Aging Effects

The aging effect (loss of material) that results from contact of the condensate system, structures, and components with the environments shown in Table 3.4-3 of the LRA is consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.4.3.2.2 Aging Management Programs

Table 3.4-3 of the LRA states that the following AMPs are credited for manage the aging effect of loss of material for the condensate system components:

- chemistry control program
- fluid leak management program
- inspection program for civil engineering structures and components

The chemistry control program, fluid leak management program, and inspection program for civil engineering structures and components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-3, the staff concludes that the above identified AMPs will effectively manage the aging effects of the condensate system and that there is reasonable assurance that the intended functions of the condensate system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.3.3 Conclusion

The staff reviewed the information in Table 3.4-3, "Condensate System." On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effect associated with the condensate system will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.4 Condensate Storage System

The condensate storage system is described in Section 2.3.4.4, "Condensate Storage System" of the LRA. The applicant described the results of its AMR of the condensate storage system for license renewal in Table 3.4-4 of the LRA.

3.4.4.1 Technical Information in the Application

The condensate storage system provides a source of water for various plant equipment as required during all modes of plant operation, including condensate cleanup, startup, normal operation, and shutdown. The condensate storage system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. The mechanical components for Catawba condensate storage system subject to aging management review, their intended functions, and materials of construction for the condensate storage system are listed in Table 3.4-4 of the LRA. No portion of the McGuire condensate storage system is within the scope of license renewal.

3.4.4.1.1 Aging Effects

The material of construction for the condensate storage system, structures, and components is carbon steel. A description of the internal environments for the condensate storage system is provided in Table 3.4-4 of the LRA. The condensate storage system components are internally exposed to a treated water environment. External surfaces of the structures and components are exposed to sheltered environment, which is discussed in Section 3.4.1 of the LRA.

Loss of material in carbon steel components in a sheltered environment was identified as the only aging effect associated with the condensate storage system, structures, and components that requires management.

3.4.4.1.2 Aging Management Programs

The applicant identified the following AMPs to manage the aging effect of loss of material for the condensate storage system components:

- chemistry control program
- fluid leak management program
- inspection program for civil engineering structures and components

A description of these AMPs, along with the applicant's discussion of how that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of the LRA: Section B.3.6, "Chemistry Control Program;" Section B.3.15, "Fluid Leak Management Program;" and Section B.3.21, "Inspection Program for Civil Engineering Structures and Components."

3.4.4.2 Staff Evaluation

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging on the condensate storage system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.4.2.1 Aging Effects

The aging effect that results from contact of the condensate storage system, structures, and components with the environments shown in Table 3.4-4 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.4.4.2.2 Aging Management Programs

Table 3.4-4 of the LRA states that the following AMPs are credited for managing the aging effect of loss of material for the condensate storage system components:

- chemistry control program
- fluid leak management program
- inspection program for civil engineering structures and components

The chemistry control program, fluid leak management program, and inspection program for civil engineering structures and components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-4, the staff concludes that the above identified AMPs will effectively manage the aging effects of the condensate storage system and that there is reasonable assurance that the intended functions of the condensate storage system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.4.3 Conclusion

The staff reviewed the information in Table 3.4-4, “Condensate Storage System.” On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effect associated with the condensate storage system will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.5 Feedwater System

The feedwater system is described in Section 2.3.4.5, “Feedwater System” of the LRA. The applicant described the results of its AMR of the feedwater system for license renewal in Table 3.4-5 of the license renewal application.

3.4.5.1 Technical Information in the Application

The feedwater system takes treated condensate system water, heats it further to improve the plant's thermal cycle efficiency, and delivers it at the required flow rate, pressure and temperature to the steam generators. The feedwater system is designed to maintain proper water levels in the steam generators with respect to reactor power output and turbine steam requirements. The mechanical components subject to AMR, their intended functions, and materials of construction for the feedwater system are listed in Table 3.4-5 of the LRA.

3.4.5.1.1 Aging Effects

The material of construction for the feedwater system, structures, and components are carbon steel, low-alloy steel, and stainless steel.

A description of internal and external environments is provided in Table 3.4-5 of the LRA. The feedwater system components are internally exposed to treated water. External surfaces of the structures and components that require an AMR are exposed to the reactor building, sheltered and yard environments, as defined in Section 3.4.1 of the LRA.

The applicant identified the following aging effects associated with the feedwater system, structures, and components, that require management:

- cracking and loss of material of stainless steel components in the treated water environment
- loss of material from carbon steel and low-alloy steel components in the treated water, reactor building, sheltered and yard atmosphere/weather environments.

The LRA did not identify an aging effect for the stainless steel components exposed to the external environments such as reactor building, sheltered and yard atmosphere/weather environments.

3.4.5.1.2 Aging Management Programs

The applicant identified the following aging management programs (AMPs) to manage the aging effects of cracking and loss of material for the feedwater system components:

- chemistry control program
- flow accelerated corrosion program
- fluid leak management program
- inspection program for civil engineering structures and components

A description of these AMPs, along with the applicant's discussion of how that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of the LRA: Section B.3.6, "Chemistry Control Program," Section B.3.14, "Flow Accelerated Corrosion Program," Section B.3.15, "Fluid Leak Management Program," and Section B.3.21, "Inspection Program for Civil Engineering Structures and Components."

To manage the aging effects for the carbon steel, alloy steel, and stainless steel components exposed to an internal environment of treated water, the applicant identified the chemistry control program.

To manage the aging effects for the carbon steel cavitating venturies (Catawba only), pipes, and valve bodies, that are exposed to an internal environment of treated water, the applicant identified the flow-accelerated corrosion program.

To manage the aging effects for the carbon steel and alloy steel components exposed to an external environment of borated water leaks in the reactor building, the applicant identified the fluid leak management program.

To manage the aging effects for the carbon steel and alloy steel components exposed to the external environments of sheltered, reactor building, and yard, the applicant identified the inspection program for civil engineering structures and components.

3.4.5.2 Staff Evaluation

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging on the feedwater system will be adequately managed during the period of extended operation as required by 54.21(a)(3).

3.4.5.2.1 Aging Effects

The aging effects that result from contact of the feedwater system, structures, and components with environments as shown in Table 3.4-5 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.4.5.2.2 Aging Management Programs

Table 3.4-5 of the LRA states that the following aging management programs are credited for managing the aging effects of cracking and loss of material for the feedwater system components:

- chemistry control program
- flow accelerated corrosion program
- fluid leak management program
- inspection program for civil engineering structures and components

The chemistry control program, flow accelerated corrosion program, fluid leak management program, and inspection program for civil engineering structures and components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-5, the staff concludes that the above identified AMPs will effectively manage the aging effects of the feedwater system and that there is reasonable assurance that the intended functions of the feedwater system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.5.3 Conclusion

The staff reviewed the information in Table 3.4-5, "Feedwater System." On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the feedwater system will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the current licensing basis (CLB) during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.6 Feedwater Pump Turbine Exhaust System

The feedwater pump turbine exhaust system is described in Section 2.3.4.6, "Feedwater Pump Turbine Exhaust System" of the LRA. The applicant described the results of its AMR of the feedwater pump turbine exhaust system for license renewal in Table 3.4-6 of the LRA.

3.4.6.1 Technical Information in the Application

The feedwater pump turbine exhaust system provides a flow path for the exhaust steam from the turbine-driven auxiliary feedwater pump turbine. The steam to the turbine-driven auxiliary feedwater pump turbine is provided by the main steam system. The Catawba UFSAR Sections 10.3, "Main Steam System," provides additional information concerning the design and operation of these systems. The mechanical components subject to AMR, their intended functions, and materials of construction for the feedwater pump turbine exhaust system are listed in Table 3.4-6 of the LRA

3.4.6.1.1 Aging Effects

The material of construction for the feedwater pump turbine exhaust system, structures, and components are carbon steel and stainless steel.

A description of internal and external environments is provided in Table 3.4-6 of the LRA. The feedwater pump turbine exhaust system components are internally exposed to treated water. External surfaces of the structures and components that require AMR are exposed to the sheltered and yard environments, as defined in Section 3.4.1 of the LRA.

The applicant identified the following aging effects associated with the feedwater pump turbine exhaust system, structures, and components, that require management:

- cracking and loss of material of stainless steel components in the treated water environment
- loss of material from carbon steel in treated water, sheltered, and yard atmosphere/weather environments

The applicant did not identify an aging effect for the stainless steel components exposed to sheltered and yard atmosphere/weather environments.

3.4.6.1.2 Aging Management Programs

The applicant identified the following AMPs to manage aging effects for the feedwater pump turbine exhaust system components:

- chemistry control program
- flow accelerated corrosion program (McGuire only)
- fluid leak management program
- inspection program for civil engineering structures and components

A description of these AMPs, along with the applicant's discussion of how that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of the LRA: Section B.3.6, "Chemistry Control Program," Section B.3.14, "Flow Accelerated Corrosion Program," Section B.3.15, "Fluid Leak Management Program," and Section B.3.21, "Inspection Program for Civil Engineering Structures and Components."

To manage the aging effects for the carbon steel and stainless steel components exposed to an internal environment of treated water, the applicant identified the chemistry control program.

To manage the aging effects for the carbon steel pipe (McGuire only) exposed to an internal environment of treated water, the applicant identified the flow accelerated corrosion program.

To manage the aging effects for the outside surface of the carbon steel components exposed to borated water leaks in the sheltered environment, the applicant identified the fluid leak management program.

To manage the aging effects for the carbon steel components exposed to the external environments of sheltered and yard, the applicant identified the inspection program for civil engineering structures and components.

3.4.6.2 Staff Evaluation

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging on the feedwater pump turbine exhaust system will be adequately managed during the period of extended operation as required by 54.21(a)(3).

3.4.6.2.1 Aging Effects

The aging effects that result from contact of the feedwater pump turbine exhaust system, structures, and components with environments as shown in Table 3.4-6 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.4.6.2.2 Aging Management Programs

Table 3.4-6 of the LRA states that the following AMPs are credited for managing the aging effects of cracking and loss of material for the feedwater pump turbine exhaust system components:

- chemistry control program
- flow accelerated corrosion program (McGuire only)
- fluid leak management program
- inspection program for civil engineering structures and components

The chemistry control program, flow accelerated corrosion program, fluid leak management program, and inspection program for civil engineering structures and components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-6, the staff concludes that the above identified AMPs will effectively manage the aging effects of the feedwater pump turbine exhaust system and that there is reasonable assurance that the intended functions of the feedwater pump turbine exhaust system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.6.3 Conclusion

The staff reviewed the information in Table 3.4-6, "Feedwater Pump Turbine Exhaust System." On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the feedwater pump turbine exhaust system will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.7 Main Steam System

The main steam system is described in Section 2.3.4.8, “Main Steam System” of the LRA. The applicant described the results of its AMR of the main steam system for license renewal in Table 3.4-7 of the LRA.

3.4.7.1 Technical Information in the Application

The main steam system dissipates heat from the RCS, provides main steam overpressure protection, minimizes positive reactivity effects associated with a main steam line rupture, minimizes the containment temperature increase associated with a main steam line rupture within containment, and provides steam to the turbine driven auxiliary feedwater pump, as needed. The mechanical components subject to AMR, their intended functions, and materials of construction for the main steam system are listed in Table 3.4-7 of the LRA. No portion of the McGuire main steam system is within the scope of license renewal.

3.4.7.1.1 Aging Effects

The materials of construction for the main steam system, structures, and components are carbon steel and stainless steel.

A description of internal and external environments is provided in Table 3.4-7 of the LRA. The main steam system components are internally exposed to treated water. External surfaces of the structures, and components that require AMR are exposed to reactor building, sheltered, and yard/weather environments. These environments are defined in Section 3.4.1 of the LRA.

The applicant identified the following aging effects associated with the main steam system, structures, and components that require management:

- cracking and loss of material of stainless steel components in the treated water environment
- loss of material from carbon steel components in the treated water, reactor building, sheltered and yard atmosphere/weather environments

The applicant did not identify an aging effect for the stainless steel components exposed to the reactor building, sheltered and yard environments for the main steam system.

3.4.7.1.2 Aging Management Programs

The applicant identified the following aging management programs to manage aging effects for the main steam system components:

- chemistry control program
- fluid leak management program
- inspection program for civil engineering structures and components

A description of these AMPs, along with the applicant’s discussion of how that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of the LRA: Section B.3.6, Chemistry Control Program,” Section B.3.15, “Fluid Leak Management Program,” and Section B.3.21, “Inspection Program for Civil Engineering Structures and Components.”

To manage the aging effects for the carbon steel and stainless steel components exposed to an internal environment of treated water, the applicant identified the chemistry control program.

To manage the aging effects for the carbon steel components exposed to an external environment of borated water leaks in the sheltered and reactor building, the applicant identified the fluid leak management program.

To manage the aging effects for the carbon steel components exposed to the external environments of sheltered, reactor building, and yard, the applicant identified the inspection program for civil engineering structures and components.

3.4.7.2 Staff Evaluation

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging on the main steam system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.7.2.1 Aging Effects

The aging effects that result from contact of the main steam system, structures, and components with environments as shown in Table 3.4-7 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.4.7.2.2 Aging Management Programs

Table 3.4-7 of the LRA states that the following aging management programs are credited for managing the aging effects of cracking and loss of material for the main steam system components:

- chemistry control program
- fluid leak management program
- inspection program for civil engineering structures and components

The chemistry control program, fluid leak management program, and inspection program for civil engineering structures and components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-7, the staff concludes that the above identified AMPs will effectively manage the aging effects of the main steam system and that there is reasonable assurance that the intended functions of the main steam system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.7.3 Conclusion

The staff reviewed the information in Table 3.4-7, “Main Steam System.” On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the main steam system will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.8 Main Steam Supply to Auxiliary Equipment System

The main steam supply to auxiliary equipment system is described in Section 2.3.4.9, “Main Steam Supply to Auxiliary Equipment System” of the LRA. The applicant described the results of its AMR of the main steam supply to auxiliary equipment system for license renewal in Table 3.4-8 of the LRA.

3.4.8.1 Technical Information in the Application

The main steam supply to auxiliary equipment transfers steam to the turbine driven auxiliary feedwater pump turbine, so that the design bases of the auxiliary feedwater system can be met. The Catawba and McGuire UFSAR Section 10.3, “Main Steam Supply System,” provides additional information concerning the main steam supply to auxiliary equipment. The mechanical components subject to AMR, their intended functions, and materials of construction for the main steam supply to auxiliary equipment system are listed in Table 3.4-8.

3.4.8.1.1 Aging Effects

The materials of construction for the main steam supply to auxiliary equipment system, structures, and components are carbon steel and stainless steel.

A description of internal and external environments is provided in Table 3.4-8 of the LRA. The main steam supply to auxiliary equipment system components are internally exposed to treated water. External surfaces of the structures, and components that require AMR are exposed to the sheltered atmosphere environment, which is defined in Section 3.4.1 of the LRA.

The applicant identified the following aging effects associated with the main steam supply to auxiliary equipment system, structures, and components that require management:

- cracking and loss of material of stainless steel components in the treated water environment.
- loss of material from carbon steel components in the treated water and sheltered environments.

The applicant did not identify an aging effect for the stainless steel components exposed to the sheltered atmosphere environment for the main steam supply to auxiliary equipment system.

3.4.8.1.2 Aging Management Programs

The applicant identified the following aging management programs to manage aging effects for the main steam supply to auxiliary equipment system components:

- chemistry control program
- fluid leak management program
- inspection program for civil engineering structures and components

A description of these aging management programs, along with the applicant's discussion of how that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of the LRA: Section B.3.6, Chemistry Control Program;" Section B.3.15, "Fluid Leak Management Program;" and Section B.3.21, "Inspection Program for Civil Engineering Structures and Components."

To manage the aging effects for the carbon steel and stainless steel components exposed to an internal environment of treated water, the applicant identified the chemistry control program.

To manage the aging effects for the outside surface of carbon steel components exposed to borated water leaks in the sheltered environment, the applicant identified the fluid leak management program.

To manage the aging effects for the outside surface of the carbon steel components exposed to the sheltered environment, the applicant identified the inspection program for civil engineering structures and components.

3.4.8.2 Staff Evaluation

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging on the main steam supply to auxiliary equipment system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.8.2.1 Aging Effects

The aging effects that result from contact of the main steam supply to auxiliary equipment system, structures, and components with environments as shown in Table 3.4-8 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.4.8.2.2 Aging Management Programs

Table 3.4-8 of the LRA states that the following aging management programs are credited for managing the aging effects of cracking and loss of material for the main steam supply to auxiliary equipment system components:

- chemistry control program
- fluid leak management program
- inspection program for civil engineering structures and components

The chemistry control program, fluid leak management program, and inspection program for civil engineering structures and components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-8, the staff concludes that the above identified AMPs will effectively manage the aging effects of the main steam supply to auxiliary equipment system and that there is reasonable assurance that the intended functions of the main steam supply to auxiliary equipment system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.8.3 Conclusion

The staff reviewed the information in Table 3.4-8, "Main Steam Supply to Auxiliary Equipment System." On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the main steam supply to auxiliary equipment system will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.9 Main Steam Vent to Atmosphere System

The main steam vent to atmosphere system is described in Section 2.3.4.10, "Main Steam Vent to Atmosphere System" of the LRA. The applicant described the results of its AMR of the main steam vent to atmosphere system for license renewal in Table 3.4-9 of the LRA.

3.4.9.1 Technical Information in the Application

The main steam vent to atmosphere system dissipates heat from the RCS, provides main steam overpressure protection, minimizes positive reactivity effects associated with a main steam line rupture, and minimizes the containment temperature increase associated with a main steam line rupture within containment. The Catawba and McGuire UFSAR Section 10.3, "Main Steam Supply System," provides additional information concerning the main steam supply to auxiliary equipment. The mechanical components subject to AMR review, their intended functions, and materials of construction for the main steam vent to atmosphere system are listed in Table 3.4-9 of the LRA.

3.4.9.1.1 Aging Effects

The materials of construction for the main steam vent to atmosphere system, structures, and components are carbon steel and stainless steel.

A description of internal and external environments is provided in Table 3.4-9 of the LRA. The main steam vent to atmosphere system components are internally exposed to treated water. External surfaces of the structures, and components that require AMR are exposed to sheltered and yard/weather environments. These environments are defined in Section 3.4.1 of the LRA. The applicant identified the following aging effects associated with the main steam vent to atmosphere system, structures, and components that require management:

- cracking and loss of material of stainless steel components in the treated water environment
- loss of material from carbon steel components in the treated water and sheltered environments.

The applicant did not identify an aging effect for the stainless steel components exposed to the sheltered environment for the main steam vent to atmosphere system.

3.4.9.1.2 Aging Management Programs

The applicant identified the following aging management programs to manage aging effects for the main steam vent to atmosphere system components:

- chemistry control program
- fluid leak management program
- inspection program for civil engineering structures and components

A description of these aging management programs, along with the applicant's discussion of how that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of the LRA: Section B.3.6, Chemistry Control Program"; Section B.3.15, "Fluid Leak Management Program"; and Section B.3.21, "Inspection Program for Civil Engineering Structures and Components."

To manage the aging effects for the carbon steel and stainless steel components exposed to an internal environment of treated water, the applicant identified the chemistry control program.

To manage the aging effects for the outside surface of the carbon steel components exposed to borated water leaks in the sheltered environment, the applicant identified the fluid leak management program.

To manage the aging effects for the carbon steel components exposed to the external environments of sheltered and yard, the applicant identified the inspection program for civil engineering structures and components.

3.4.9.2 Staff Evaluation

The staff reviewed the results of the applicant’s AMR to determine whether the applicant had demonstrated that the effects of aging on the main steam vent to atmosphere system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.9.2.1 Aging Effects

The aging effects that result from contact of the main steam vent to atmosphere system, structures, and components with environments as shown in Table 3.4-9 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments listed.

3.4.9.2.2 Aging Management Programs

Table 3.4-9 of the LRA states that the following aging management programs are credited for managing the aging effects of cracking and loss of material for the main steam vent to atmosphere system components:

- chemistry control program
- fluid leak management program
- inspection program for civil engineering structures and components

The chemistry control program, fluid leak management program, and inspection program for civil engineering structures and components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff’s evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-9, the staff concludes that the above identified AMPs will effectively manage the aging effects of the main steam vent to atmosphere system and that there is reasonable assurance that the intended functions of the main steam vent to atmosphere system will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.9.3 Conclusion

The staff reviewed the information in Table 3.4-9, “Main Steam Vent to Atmosphere System.” On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the main steam vent to atmosphere system will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.10 Aging Management Review for Closure Bolting in Steam and Power Conversion Systems

Although the LRA provided AMR results for Class 1 bolting, it did not address bolting for

Non-Class 1 components. By letter dated January 23, 2002, the staff requested, in RAI 3.2-1, additional information that pertains to tables in Sections 3.2, 3.3, and 3.4 of the LRA that list closure bolting as components subject to AMR. The staff stated that since closure bolting is exposed to air, moisture, and leaking fluid (boric acid) environments, it is subject to the aging effect of loss of material and crack initiation and growth. Tables in Sections 3.2, 3.3 and 3.4 do not address these aging effects for closure bolting in these systems. The staff requested the applicant to identify the AMR results for closure bolting, or to provide a justification for excluding closure bolting from an AMR, the results of which are documented in the referenced tables of the LRA.

3.4.10.1 Aging Effects

The applicant indicated that non-class 1 mechanical components within the scope of license renewal contain bolted closures that are necessary for the pressure boundary of the component. Examples of these bolted closures are valve bonnet to body closures, pump cover to casing closures, heat exchanger manway and end-bell closures and piping flange sets. The bolted closure is comprised of two mating surfaces, a gasket, and a fastener set of studs or bolts and nuts. By themselves, the mating set, gasket, and fastener set have no component intended function. Together, the bolted closure forms an integral part of the pressure-retaining boundary of the component. Gaskets are not relied upon for pressure boundary of the bolted closure in accordance with the design codes and are not subject to an aging management review.

Bolted closures are exposed to two environments. The mating surfaces are exposed internally to the process fluid while the external surfaces and the fastener set are exposed to the ambient environment where the bolted closures are located. Aging effects for external and internal surfaces of the mating set of bolted closures are the same as other components in the system of the same material and exposed to the same environment. Programs for the system (i.e., chemistry in a treated water system and fluid leak management program) containing the bolted closure are applicable to the mating set and are not discussed here further.

The aging effects for the fastener set of non-Class 1 bolted closures are loss of material of carbon and low alloy steel and cracking of carbon, low alloy, and stainless steels. Loss of material of the fastener set of the bolted closure may occur as a result of fluid leakage, use of an improper lubricant during assembly, or exposure to the ambient environment. Cracking of the fastener set of bolted closures may occur as a result of improper material selection, improper torquing during assembly, use of an improper lubricant, fluid leakage, or exposure to the ambient environment. Of these aging effects, Duke determined the following are the aging effects requiring management for carbon and low alloy steel fastener sets:

- loss of material of the fastener set due to boric acid exposure;
- loss of material of the fastener set in systems with operating temperatures below ambient conditions that result in condensation; and
- loss of material of the fastener set in the yard environment that are repeatedly wetted and dried from exposure to the elements.

The applicant stated that no aging effects requiring management were identified for the stainless steel fastener set of bolted closures.

On the basis of its review of the RAI response pertaining to Non-Class 1 bolting, the staff finds that all applicable aging effects were identified, and the aging effects identified are appropriate for the combination of materials and environments listed.

3.4.10.2 Aging Management Programs

The applicant indicated that the Fluid Leak Management Program will manage loss of material of non-Class 1 bolted closures in the Reactor and Auxiliary Buildings due to leakage from systems containing boric acid. No systems containing boric acid are located outside these two buildings. The Fluid Leak Management Program is described in Appendix B, Section B.3.15 of the LRA for McGuire and Catawba.

The Inspection Program for Civil Engineering Structures and Components will manage loss of material of non-Class 1 bolted closures in systems with operating temperatures below the surrounding ambient environment that are wet with condensation. In addition, this program will also manage loss of material of non-Class 1 bolted closures located in the yard that are repeatedly wetted and dried from exposure to the elements. The Inspection Program for Civil Engineering Structures and Components is described in Appendix B, Section B.3.21 of the LRA for McGuire and Catawba.

The Fluid Leak Management program and the Inspection Program for Civil Engineering Structures and considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for Non-Class 1 closure bolting. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

3.4.10.3 Conclusions

Based on the above discussion, the staff finds that the applicant's response clarifies and satisfactorily resolves this issue concerning the closure bolting in mechanical systems as described in RAI 3.2-1. The staff concludes that the applicant has demonstrated that the aging effects associated with Non-Class 1 closure bolts will be adequately managed so there is reasonable assurance that these components will perform their intended functions consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.11 References

3.4.11.1 M. S. Tuckman (Duke) letter dated June 13, 2001 to Document Control Desk (NRC), License Renewal Evaluation Boundary Drawings. McGuire Nuclear Station, Units 1 and 2 and Catawba Nuclear Station, Units 1 and 2, Docket Nos. 50-369, 50-370, 50-413, and 50-414.

3.4.11.2 Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants, Draft, NRC, August 2000.

3.4.11.3 Catawba Nuclear Station Units 1 and 2, Updated Final Safety Analysis Report.

3.4.11.4 McGuire Nuclear Station Units 1 and 2, Updated Final Safety Analysis Report.

3.4.11.5 NUREG-1723, Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3, March 2000, U. S. Nuclear Regulatory Commission, Docket Nos. 50-269, 50-270, and 50-287.

3.4.11.6. NUREG-1801, Generic Aging Lessons Learned (GALL) Report, Volumes 1 and 2, U. S. Nuclear Regulatory Commission, July 2001.

3.4.11.7 NUREG-1743, Safety Evaluation Report Related to the License Renewal of Arkansas Nuclear One, Unit 1, May 2001, U. S. Nuclear Regulatory Commission, Docket No. 50-313.

3.5 Aging Management of Containments, Structures and Component Supports

3.5.1 Reactor Building

3.5.1.1 Technical Information in the Application

The aging management review results for the reactor buildings, including the concrete shield building, the steel containment, the ice condenser components and all of the reactor building interior structural components, except component supports, are presented in Table 3.5-1 of the LRA. Table 3.5-1 of the LRA identifies the components that constitute the reactor building along with the component (1) function, (2) material, (3) environment, (4) aging effects, and (5) aging management programs and activities.

Section 2.4.1 of the LRA states that the concrete shield building (or reactor building) structure is part of the containment system, which is designed to ensure that an acceptable upper limit of leakage of radioactive material is not exceeded under design basis events. The reactor building is a seismic Category I structure at both the McGuire and Catawba nuclear stations. Each reactor building is a reinforced concrete structure composed of a right cylinder with a shallow dome and flat circular foundation. The reactor building houses the steel containment vessel and is designed to provide biological shielding as well as missile protection for the steel containment vessel. The materials of construction for the concrete shield building, as shown in Table 3.5-1 of the LRA, are primarily concrete and include the dome, foundation mat, and shell wall. Table 3.5-1 also identifies the steel foundation dowels as an in-scope component for the McGuire nuclear station concrete shield building. The concrete shield building components are exposed to (1) external, (2) reactor building, and (3) below grade environments. The McGuire nuclear station foundation dowels are enclosed in concrete.

Section 2.4.1 of the LRA states that the steel containment surrounds the RCS and functions as the primary containment. The steel containment is a freestanding welded seismic Category I steel structure with a vertical cylinder, hemispherical dome, and a flat base. The steel containment shell is anchored to the concrete shield building foundation by means of anchor bolts around the circumference of the cylinder base. The base of the containment is a liner plate encased in concrete and anchored to the concrete shield building foundation. The materials of construction for the steel containment, as shown in Table 3.5-1 of the LRA, are either carbon steel or stainless steel and include the (1) steel containment vessel, (2) mechanical, electrical, and fuel transfer tube penetrations, (3) equipment hatch, (4) personnel air locks, and (5) bellows. Each of the steel containment components are exposed to an internal (reactor building) environment.

The ice condenser structural components are part of the reactor building internal structures. The materials of construction for the ice condenser components, as shown in Table 3.5-1 of the LRA, are carbon steel, galvanized steel, and concrete and include the (1) ice baskets, (2) lattice frames and support columns, (3) doors, (4) lower support structure, and (5) wear slab. Each of the ice condenser components are exposed to an internal (ice condenser or reactor building) environment.

Section 2.4.1 of the LRA states that the reactor building internal structures consist of a variety of reinforced concrete and structural steel structures. The internal structures enclose the RCS and provide biological shielding and pressure boundaries for the lower, intermediate, and upper volumes of the containment interior. These structures also provide support and restraint for all major equipment, components, and systems located within the Reactor Building. The internal structures are supported on the concrete reactor building foundation. The materials of construction for the reactor building interior structural components, as shown in Table 3.5-1 of the LRA, are carbon steel, stainless steel and concrete and include anchorages, embedments, equipment pads, flood curbs, hatches, shields, floor slabs, walls, beams, and columns.. The pressure seals and gaskets used in the reactor building are made of ethylene propylene dienyl monomer (EPDM). The reactor building internal structural components are exposed to internal (reactor building) and external (equipment hatch missile shield) environments. The anchorages and embedments are encased within concrete.

3.5.1.1.1 Aging Effects

Table 3.5-1 of the LRA identifies the following applicable aging effects for components that constitute the reactor building:

- change in material properties for concrete components in the concrete shield building that are exposed to an external environment
- loss of material of carbon steel components exposed to an internal (reactor building, ice condenser) environment
- cracking of stainless steel penetration bellows in the reactor building
- loss of material of the galvanized steel ice baskets in the ice condenser
- cracking and change in material properties for the EPDM pressure seals and gaskets in the reactor building

3.5.1.1.2 Aging Management Programs

Table 3.5-1 of the LRA credits the following aging management programs with managing the identified aging effects for the components that constitute the reactor building:

- Containment Leak Rate Testing Program
- Containment ISI Plan - IWE
- Ice Condenser Inspections
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- Divided Barrier Seal Inspection and Testing Program
- Technical Specification SR 3.6.16.3 Visual Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in the reactor building will be adequately managed by these aging management programs during the period of extended operation.

3.5.1.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures" and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the reactor building structural members have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management programs credited for the aging management of the reactor building structural members at McGuire and Catawba nuclear stations. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the reactor building structural members.

3.5.1.2.1 Aging Effects

Section 3.5.1 of the LRA provides an aging management review of the reactor building structural components. Table 3.5-1 of the LRA is divided into four sections: (1) concrete shield building, (2) steel containment, (3) ice condenser components, and (4) reactor building interior structural components. The staff's evaluation of the applicant's aging management review for these components follows.

Concrete
The applicant identified change in material properties as the only applicable aging effect for the concrete dome and shell wall of the concrete shield building. These two components are exposed to an external environment. No aging effects are identified in Table 3.5-1 for the other concrete components of the reactor building. The other concrete components of the reactor building are exposed to internal (reactor building, ice condenser), and below grade environments.

In addition to change in material properties, the staff considers cracking and loss of material to be both plausible and applicable aging effects for the concrete components of the reactor building that are exposed to either internal (reactor building, ice condenser) or external (outdoor) environments. The NRC staff position regarding the aging management of in-scope concrete structures and components (SCs) is that concrete SCs need to be periodically inspected in order to adequately monitor their performance or condition in a manner that allows for the timely identification and correction of degraded conditions. Concrete SCs in nuclear power plants are prone to various types of age-related degradation depending on the stresses and strains, due to normal and incidental loadings, as well as the environment to which they are subjected. Concrete SCs subjected to sustained loading, such as crane or monorail operation, and/or sustained adverse environmental conditions, such as high temperatures, humidity, or chlorides, will degrade, thereby potentially affecting the intended function(s) of the SCs. These degradations to concrete SCs are manifested through aging effects such as cracking, loss of material, and change in material properties. As concrete SCs age, such aging effects accentuate. On the basis of industry-wide evidence, the American Concrete Institute (ACI) has published a number of documents (e.g., ACI 201.1R, "Guide for Making a Condition Survey of

Concrete," ACI 224.1R, "Causes, Evaluation and Repairs of Cracks in Concrete Structures," and ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures") that identify the need to manage the aging of concrete structures. These reports and standards confirm the inherent characteristics of concrete structures to degrade, with time, if not properly managed. Similar observations of concrete aging, made by NRC staff, are detailed in NUREG-1522, "Assessment of In-Service Conditions of Safety-Related Nuclear Power Plant Structures." As such, by letter dated January 28, 2002, the staff requested, in RAI 3.5-7, that the applicant identify the aging management program(s) that will be used to manage the aging effects for the above-grade concrete components listed in Tables 3.5-1 and 3.5-2 of the LRA.

In its response dated March 11, 2002, the applicant stated:

> Duke Power disagrees with the NRC staff position. The standards and results of NUREG-1522 inspections do not draw one to conclude that aging is an inherent characteristic of concrete, if not properly managed. Most of the industry-wide experience associated with the degradation of concrete in the standards is the result of exposure to severe environments such as marine or chloride exposure. Most, if not, all of the pictures in ACI 201.1R, "Guide for Making a Condition Survey of Concrete," depict degradation of bridges exposed to salt attack. In these environments, condition monitoring activities are appropriate.
>
> In contrast, the NRC staff fails to reference standards or reports that support the inherent durability of concrete. ACI 201.2R, "Guide to Durable Concrete," states that "durable concrete will retain its original form, quality, and serviceability when exposed to its environment." It goes on to state that "concrete will perform satisfactorily when exposed to various atmospheric conditions, to most waters and soils containing aggressive chemicals, and to many other kinds of chemical exposure."
>
> In addition, NUREG/CR-6424, "Report on Aging of Nuclear Power Plant Reinforced Concrete Structures, reports that most instances related to degradation of concrete structures in the United States occurred early in the life of the structures and have been corrected. Causes were primarily related either to improper material selection, construction/design deficiencies, or environmental effects. Examples of some of the problems attributed to these deficiencies include concrete cracking, concrete voids or honeycombing, and concrete compressive strength values that were low relative to design values at a specific concrete age. In almost all cases, the concrete cracks were considered to be structurally insignificant or easily repaired using techniques such as epoxy injection. The voids and honeycombed areas and low-strength concrete areas were repaired or replaced. Quality control/quality assurance programs at nuclear power plants generally have been very effective in ensuring that the basic factors related to the production or durable concrete are adequately addressed.
>
> NUREG/CR-4652, "Concrete Component Aging and Its Significance Relative to Life Extension of Nuclear Power Plants, contains additional information to support the durability of concrete structures. NUREG/CR-4652 contains a summary of the degradation associated with nuclear power plant structures. Although the vast majority of the problems detected did not present a threat to public safety or jeopardize the structural integrity of the particular component, five incidences were identified that if not discovered and repaired could potentially had have serious consequences. These incidences were all related to the concrete containment and involved two dome delaminations, voids under tendon bearing plates, anchor head failures, and a breakdown in quality control and construction management. These few incidences where the structural integrity of the component was jeopardized were attributed to design, construction, or human errors, but not to aging. These findings are also reported in SECY 96-080 as the basis for the revision to 10 CFR 50.55(a) to incorporate inspections in accordance with ASME Subsection IWL.
>
> NUREG/CR-4652 concludes that the results of the study are considered to be sufficiently representative that some general observations can be made on concrete aging and component performance. When concrete is fabricated with close attention to the factors required for durable concrete, the concrete will have infinite durability unless subjected to extreme external influences (overload, elevated temperatures, industrial liquids, etc.). Under normal environmental conditions aging of concrete does not have a detrimental effect on its strength for concrete ages to at least 50

> years. [Note; 50 years is the limit on age for which well-documented data has been identified. The number of concrete structures in existence having ages of 40 to 70 years, with a few in service for thousands of years, indicates that this value is conservative. Also, many structures continue to meet their function and performance requirements even conditions are far from ideal.] The overall performance of concrete components in nuclear applications has been very good. With the exception of the anchor head failures at Farley 2, errors detected during the construction phase or early in the structure's life were of no structural significance or "easily" repaired and were non-aging related.
>
> Many of the previously discussed documents were complete prior to 1990. More recent concrete inspection findings are documented in NUREG-1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures," and NUREG/CR-6679, "Assessment of Age-Related Degradation of Structures and Passive Components for U.S. Nuclear Power Plants." These documents identify concrete cracking in various structures at several nuclear plant sites. The documents do not discuss the severity or impact of the cracking on the functional capabilities of the component. All cracks do not necessarily result in loss of the intended function. For example, ACI 349.3R provides guidance on the size of cracks which would be judged to be acceptable. Furthermore, the pictures in NUREG-1522 do not depict cracking that would result in loss of intended function of the concrete component or structure. The findings do support the need for concrete inspections in certain structures which are exposed to environments that may result in aging such as salt water, brackish water, etc. Duke agrees with this position as evidenced by the information in the Application. For example, loss of material and cracking are identified as aging effects in Table 3.5-2 for reinforced concrete beams, columns, and walls that are exposed to a raw water environment. The findings do not support the need for inspections of all concrete structures in all environments.
>
> The aging management review for the identified concrete components was conducted in accordance with the guidance provided in NEI 95-10, which was endorsed by the NRC, and incorporates findings from NUREG-1557, NUREG-1522, NUREG/CR-6424, NUREG/CR-4652, and ACI standards. Based on the material/environment combinations, it was determined that no aging effects would occur for these components that would result in loss of the intended function for the period of extended operation. Therefore, no aging management programs are required.

The applicant stated in its response to RAI 3.5-7 that the severity of the age-related degradations to concrete nuclear structures, observed by the staff and industry, would not result, for most cases, in loss of intended function for these concrete components. Therefore, only concrete nuclear components and structures that are exposed to harsh or extreme environments, which would result in rapid aging, need aging management during the period of extended operation. The applicant cited the sound material design and construction of concrete components as the primary factor for its durability and resistance to aging.

The staff takes exception to the applicant's claim that aging management of concrete components via periodic inspections is only necessary for concrete SCs that are exposed to harsh environments. Both the operating and environmental conditions as well as the aging of concrete nuclear components are subject to change throughout the period of extended operation and thus, applicants need to periodically inspect these components. ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," is a report that represents a consensus of knowledgeable individuals from nuclear industry, consultants, and regulators. As stated in ACI 349.3R, sound engineering practices during material (concrete mix) design and construction together with sound inspection programs, in which the performance and condition are periodically evaluated and monitored, are <u>both</u> necessary to maintain the serviceability of concrete nuclear structures. Periodic visual inspections (1) can provide significant quantitative and qualitative data regarding structural performance and extent of degradation, (2) are vital to monitor the effects of operating and environmental conditions, and (3) enable the timely identification and correction of degraded conditions.

The staff recognizes that the applicant has performed an aging management review by 10 CFR 54.21(a)(3) for each structure and component that was determined to be in the scope of license renewal. The staff position regarding the aging management reviews of concrete components performed by license renewal applicants is that they should be used to differentiate between those components requiring only periodic inspections and those requiring further evaluation, as documented in interim staff guidance issued on April 5, 2002 (ML020980194). Aging management review results of concrete structures and components may also be used to establish different scheduled inspection frequencies, similar to those recommended by ACI 349.3R, for aging management programs.

In conclusion, periodic inspections of concrete components during the period of extended operation are necessary in order for the staff to make a reasonable assurance finding that in-scope concrete structures and components will maintain their structural integrity and intended function(s). Periodic visual inspections of concrete nuclear structures are a vital part of the license renewal program. On this basis, the staff disputes the applicant's claim, in response to RAI 3.5-7, that aging management programs are necessary only for the above-grade concrete components, listed in Tables 3.5-1 and 3.5-2 of the LRA, that are exposed to harsh environments. This issue is characterized as open item 3.5-1.

For below-grade concrete components, the staff has determined that aging management is unnecessary if applicants are able to show that the below-grade soil/groundwater environment is non-aggressive. By letter dated January 28, 2002, the staff requested, In RAI 3.5-1, that the applicant provide further information regarding the chemistry of the groundwater samples taken at both Catawba and McGuire nuclear stations. In addition, the staff requested that the applicant provide the frequency for future groundwater sampling in order to demonstrate that the condition of the below-grade environment for concrete components remains non-aggressive during the period of extended operation. In its response dated March 11, 2002, the applicant stated:

> The environmental parameters of the below grade environment are discussed in Section 3.5.1 of the Application. Minimum degradation threshold limits for concrete have been established at 500 ppm chloride, 1,500 ppm sulfates, pH < 5.5 [Reference NUREG-1611]. The Catawba and McGuire groundwater parameters are below the limits where potential degradation of the concrete may occur. The environmental data for Catawba and McGuire is based on historical data during construction and data from more recent tests. The data spans more than 20 years. More than 20 years of environmental monitoring is sufficient to identify any trends toward aggressive environments; therefore, future test of groundwater chemistry are not required. The SOC for the original license renewal rule supports the use of more than 20 years of operational data as sufficient. The NRC believes that the history of operation over the minimum 20-year period provides a licensee with substantial amounts of information and would disclose any plant-specific concerns with regard to age-related degradation.

During the NRC Scoping and Screening Inspection (conducted March 18-22, 2002, and documented in NRC Inspection Report 50-369/02-05, 50-369/02-05, 50-369/02-05 and 50-369/02-05) the applicant provided data from Lake Norman, adjacent to McGuire, and Lake Wylie, adjacent to Catawba, showing pH values and phosphate, chloride and sulphate contents (ML021090060). The lake water sampling dates are from 1962 to 1996 for McGuire (Lake Norman) and from 1971 to 1996 for Catawba (Lake Wylie). In addition, the applicant referred the staff to the Environmental Reports (ERs) associated with the original construction of Catawba and McGuire. The ERs contain water table contour maps (ER Figure 2.4.4-2 for Catawba, and ER Figure 2.5.2-2, Revision 2, for McGuire).

As stated in the applicant's response to RAI 3.5.1, the chloride, sulfate, and pH values over the past 20 to 30 years are well below the limits where potential degradation of concrete may occur. As such, the applicant does not believe a commitment to periodically monitor the groundwater chemistry during the period of extended operation is warranted. In addition, the water contour tables for both Catawba and McGuire show that the water table levels decrease from the two nuclear stations outward to the surrounding areas. This implies that only a chemical event at the nuclear stations would potentially impact their respective site environments, including the groundwater. On the basis of the water sampling data from the two sites and outwardly sloping water contour tables, the staff concurs with the applicant that periodic monitoring of the groundwater during the period of extended operation is unnecessary. However, in its response to RAI 3.5-1, the applicant does not commit to initiate corrective action in the event of a potential change to the site environment resulting from a chemical release during the period of extended operation. Such a corrective action would need to include a commitment to monitor the groundwater chemistry and to assess the potential impact of any changes to the groundwater chemistry on below grade concrete components. As such, the applicant's response to RAI 3.5-1 is inadequate. This issue is characterized as open item 3.5-2.

In addition to the below grade concrete components in the reactor building, Table 3.5-1 of the LRA also does not identify any applicable aging effects for normally inaccessible concrete components such as the ice condenser wear slab. By letter dated January 28, 2002, the staff requested, in RAI 3.5-6, that the applicant describe its aging management review of inaccessible reactor building concrete components in further detail. In its response dated March 11, 2002, the applicant stated that the following areas of the reactor building are inaccessible due to the layout of the ice condenser system:

- wear slab that is located beneath a protective layer of ice
- structural concrete floor located beneath the wear slab
- surface of the crane wall that is located behind the insulated wall panels

The applicant, in its response to RAI 3.5-6, stated that these concrete components are designed in accordance with ACI and American Society for Testing and Materials (ASTM) standards, which provide for a good quality, dense, low permeability concrete that provides resistance to aggressive chemical attack and corrosion of rebar. The applicant also stated that the concrete located in the ice condenser is exposed to a unique environment. The normal atmosphere in the ice condenser is low temperature (10°F to 20°F) and very low humidity. Under these operating and environmental conditions, and considering the quality of the concrete, the applicant stated that the above concrete components would not be subject to aging effects requiring management.

Regarding the ice condenser wear slab, the applicant stated that the wear slab is constructed of dense, low permeability concrete and is protected by a coating as well as a layer of ice. The protective coating and layer of ice protect the wear slab from flowing water potentially arising from ice condenser wall panel defrosting. The applicant stated that during maintenance at either McGuire or Catawba, ice condenser wall panel defrosting is not a normal maintenance practice.

Regarding the structural concrete floor, which is located beneath the ice condenser wear slab, the applicant stated that a layer of foam concrete is located between the wear slab and the structural concrete floor to provide a layer of insulation. A vapor barrier is provided between the foam concrete and the structural concrete floor. The applicant also stated in response to RAI 3.5-6 that the structural concrete floor is accessible from below.

Regarding the crane wall, the applicant stated, in its response to RAI 3.5-6, that the interior surface of the crane wall is open to the reactor building environment and is accessible for inspection. However, the exterior surface of the crane wall is covered by wall panels in the ice condenser. Cooling ducts are incorporated into the wall panels to provide flow from the air handlers in the duct adjacent to the ice bed and return flow in the outer duct of the panel. The applicant stated that while the wall panels and cooling ducts make the exterior surface of the crane wall inaccessible for inspection, they also protect the crane wall from potential defrosting water.

Since these three normally-inaccessible ice condenser concrete components are in a unique environment of low humidity and temperature, the staff acknowledges that there are no accessible concrete components in a similar environment that the applicant could use as an indicator of the aging of these inaccessible ice condenser components. However, portions of both the structural concrete floor, which is located beneath the ice condenser wear slab, and the crane wall are accessible for inspection. The applicant stated, in its response to RAI 3.5-6, that the structural concrete floor is accessible from below and that the interior surface of the crane wall is open to the reactor building environment and is accessible for inspection. As such, based on the reasoning stated above in RAI 3.5-7 concerning the aging management for accessible concrete components, the staff considers the applicant's response to RAI 3.5-6 to be inadequate with regard to the structural concrete floor, which is located beneath the ice condenser wear slab, and the crane wall. For the ice condenser wear slab, the staff acknowledges that the slab is located beneath a layer of ice and that the slab also has a protective coating. The wear slab is also on top of the structural concrete floor and is therefore completely inaccessible for inspection. In the event of an ice condenser wall panel defrosting, the wear slab would be accessible for inspection; however, the applicant did not state, in response to RAI 3.5-6, that it would inspect the wear slab under such conditions. As such, the staff considers the applicant's response to RAI 3.5-6, with respect to each of the three ice condenser concrete components, to be inadequate. This issue is characterized as open item 3.5-3.

<u>Steel</u>
Table 3.5-1 of the LRA identifies (1) loss of material of carbon steel components exposed to an internal (reactor building, ice condenser) environment, (2) loss of material of the galvanized ice baskets in the ice condenser, and (3) cracking of the stainless steel penetration bellows in the reactor building as applicable aging effects for the steel components in the reactor building.

The staff concurs with the aging effects identified above by the applicant for the carbon steel and stainless steel components of the reactor building. However, the staff noted that no aging effects are identified in Table 3.5-1 for the stainless steel fuel transfer canal liner plate, sump liner, and sump screens. These three stainless steel components are exposed to an internal (reactor building) environment as are the stainless steel penetration bellows, for which the applicant identified cracking as an applicable aging effect. In view of this discrepancy, by letter dated January 28, 2002, the staff requested, in RAI 3.5-4, that the applicant explain why cracking is not identified as an applicable aging effect for all stainless steel components in the reactor building. In its response dated March 11, 2002, the applicant stated that its aging management review for stainless steel components in the reactor building environment did not identify any applicable aging effects for the fuel transfer canal liner plate, sump liner, and sump screens. The applicant's aging management review included a review of its own operating experience as well as industry experience regarding these three stainless steel components. However, operating experience for the penetration bellows did reveal cracking due to stress corrosion cracking from chloride concentration and leaking as an applicable aging effect.

On June 7, 2002, the staff and applicant discussed this response to RAI 3.5-4 during a conference call, which was summarized in a memorandum dated June 7, 2002 (ML021620496). During the conference call, the applicant indicated that a leaking bellows had been identified in 1993 and was replaced in 1994. In 1997, leakage from the replacement bellows was identified, and the leaking bellows was replaced. A root cause determination attributed the 1997 bellows leak to transgranular stress-corrosion cracking (TGSCC) as a result of exposure to or contact with chlorine. The applicant could not determine the source of chlorine and speculated that the contaminant could have been introduced by a surface brightener during the manufacturing process. The applicant further stated that TGSCC had not been listed as an applicable aging effect for the other components (fuel transfer canal liner plate, sump liner, and sump screens) because the normal operating environment would not expose these components to chlorine and they essentially consist of plate material that had not been polished or brightened by the manufacturer.

The staff finds the applicant's explanation of why cracking caused by TGSCC was not identified as an applicable aging effect for fuel transfer canal liner plate, sump liner, and sump screens reasonable. By letter from the applicant dated July 9, 2002, this explanation was provided in official correspondence. Therefore, this issue is resolved.

The staff noted that Table 3.5-1 of the LRA does not distinguish between accessible and inaccessible carbon steel components in the reactor building. The applicant identifies loss of material as an applicable aging effect for all of the carbon steel components in the reactor building. However, the staff noted that the applicant does not describe how it will manage the aging of the inaccessible areas of the steel liner plate and other interior structural steel components. By letter dated January 28, 2002, the staff requested, in RAI 3.5-3, that the applicant address how the potential aging effect of loss of material will be managed for inaccessible areas. In its response dated March 11, 2002, the applicant stated its aging management review of steel reactor building components did not ignore any environmental conditions to which structures and components are exposed, including those conditions in area that may turn out to be inaccessible for inspection. The applicant further stated that structures and components that are inaccessible may be exposed to unique environments because of their location. However, the applicant stated that its aging management review of the inaccessible portion of the steel components in the reactor building did not identify any inaccessible environments that result in aging effects different from those in the accessible environments. As such, no unique aging management programs were determined by the applicant to be necessary for any accessible areas. Therefore, the applicant will use the Containment ISI Plan - IWE aging management program to manage both the accessible and inaccessible portions of the steel components in the reactor building. Any evidence of aging in accessible areas will be used to provide guidance for aging effects in inaccessible areas. The staff finds the applicant's response to RAI 3.5-3 acceptable because it is consistent with regulatory guidance and industry-wide aging management of accessible and inaccessible components.

In its response to RAIs 2.4.1-1 and 2.4.1-4, the applicant identified steel penetrations as being within the scope of license renewal and provided the AMR results for the staff's review (see Section 2.4.1.1.2 of this SER). The applicant identified the reactor building as the environment for these steel penetrations and loss of material as the aging effect. The applicant credited the Inspection Program for Civil Engineering Structures and Components as the AMP. The staff finds the aging effects identified appropriate for the material and environment specified, and concludes that the aging effects will be adequately managed by the AMP identified.

The staff finds that the applicant's approach for evaluating the applicable aging effects for the steel components in the reactor building to be reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effects for steel components in the reactor building.

<u>Elastomers</u>
Table 3.5-1 of the LRA identifies cracking and change in material properties for the EPDM pressure gaskets and seals in the reactor building. The staff concurs with applicant's identification of these two aging effects for elastomer material components in the reactor building.

3.5.1.2.2 Aging Management Programs

Table 3.5-1 of the LRA credits the following aging management programs with managing the identified aging effects for the components that constitute the reactor building:

- Containment Leak Rate Testing Program
- Containment ISI Plan - IWE
- Ice Condenser Inspections
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- Divided Barrier Seal Inspection and Testing Program
- Technical Specification SR 3.6.16.3 Visual Inspection

Of the above aging management programs, the Containment Leak Rate Testing Program, Containment ISI Plan - IWE, Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for the structures that make up the reactor building. The staff's evaluation of common aging management programs is documented in Section 3.0 of the SER. The staff's evaluation of the Ice Condenser Inspections, Divided Barrier Seal Inspection and Testing Program, and Technical Specification SR 3.6.16.3 Visual Inspection aging management programs are given below.

<u>Ice Condenser Inspections</u>

The applicant described its Ice Condenser Inspections in Section B.3.18 of the LRA. The applicant credits two activities for managing the aging of the ice condenser systems. The Ice Basket Inspection is a TS surveillance that is credited with managing the loss of material of the ice baskets. The Ice Condenser Engineering Inspection is credited with managing the loss of material in the ice condenser upper plenum, lower plenum, and top blankets. The staff reviewed Section B.3.18 of the LRA to determine whether the applicant had demonstrated that the effects of aging will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

The applicant credits the following two activities for managing the aging of the ice condenser systems:

- Ice Basket Inspection
- Ice Condenser Engineering Inspection.

Loss of material of the ice condenser steel ice baskets has been identified as an aging effect requiring management for the period of extended operation. The functional integrity of the ice condenser ice baskets ensures the ice condenser will perform its intended safety function. The purpose of the Ice Basket Inspection is to manage aging effects for the period of extended operation. The Ice Basket Inspection is a visual inspection, condition monitoring program, which is a requirement of the Catawba and McGuire TS. Based on operating experience, the program has been effective in identifying deficiencies and other minor degradation (not aging related) and is capable of detecting and managing loss of material.

Loss of material due to corrosion of steel components in the ice condenser environment has been identified as an aging effect requiring management for the period of extended operation. The purpose of the Ice Condenser Engineering Inspection is to manage loss of material of the ice condenser upper plenum, lower plenum, and top deck blankets for the period of extended operation. The Ice Condenser Engineering Inspection is a visual inspection, condition monitoring program which the applicant is currently implementing as part of an engineering support program at McGuire and Catawba.

The staff's evaluation of the ice condenser inspection activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures and/or TS. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] The applicant defined the scope of the Ice Basket Inspection as including all of the ice baskets located in the ice condenser, while the scope of the Ice Condenser Engineering Inspection includes the ice condenser structural components in the upper plenum, lower plenum, and top deck blankets. Because the scope includes the structures and components that are subject to the aging effects, the staff finds the scope of the program to be acceptable.

[Preventive Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or mitigate aging degradation. The staff considers inspection activities to be a means of detecting, not preventing, aging and therefore, agrees that there are no preventive actions required.

[Parameters Inspected or Monitored] The applicant identified the parameter monitored by the Ice Condenser Inspections as loss of material. Because the visual inspections are capable of detecting degradation and loss of material of the ice condenser components, the staff finds the inspections to be acceptable.

[Detection of Aging Effects] The Ice Basket Inspection uses visual examination of the ice baskets to detect the loss of material, and the Ice Condenser Engineering Inspection uses visual inspection of the structural components in the upper plenum, lower plenum, and top deck blankets to detect loss of material. The staff finds this approach to be consistent with current industry practice and agrees that it is an acceptable method of detecting aging before loss of function.

[Monitoring and Trending] Section B.3.18 of the LRA describes the monitoring and trending. The Ice Basket Inspection requires a visual inspection performed at a 40 months frequency in accordance with TSSR 3.6.12.6. For both McGuire and Catawba, the sample includes two ice baskets from each of three azimuthal groups of bays. The Ice Basket Inspection also requires a visual inspection every refueling outage of each basket that is replenished (emptied of ice and refilled) based on ice weight and sublimation history. Records are maintained to permit confirmation of the inspection results, including any discrepancies identified, associated root cause determinations, and corrective actions taken.

The Ice Condenser Engineering Inspection consists of visual inspections every refueling outage of the structural components in the upper plenum, lower plenum, and top deck blankets. Records are maintained, and trending information is retained in files.

The baskets are monitored and maintained in accordance with the TS, and the structural components are monitored on a refueling outage frequency and trended. The staff finds these activities acceptable.

[Acceptance Criteria] The applicant described the acceptance criteria as no adverse conditions that could prevent the ice condenser from performing its intended function. Acceptance criteria include no unacceptable visual indication of material condition including corrosion, glycol leaks, and missing or loose fasteners. Because degradation is detectable by visual inspections and this approach is consistent with current industry practice, the acceptance criteria are acceptable to the staff.

[Operating Experience] The applicant reported that a review of the Ice Basket Inspection conducted at McGuire and Catawba confirms the reasonableness and acceptability of the inspection frequency in that degradation of the ice basket is detected prior to loss of function. Identified deficiencies were associated primarily with missing screws and minor dents on the ice baskets. These deficiencies were attributed to ice basket maintenance (i.e., weighing, replenishing ice, etc.), and were not age-related. Repairs were performed at the time of inspection under the guidance of site procedures.

The applicant reported that a review of previous Ice Condenser Engineering Inspections conducted at McGuire and Catawba confirms the reasonableness and acceptability of the inspection frequency in that degradation of ice condenser structural components is detected prior to loss of function. The applicant reported that the majority of work orders were generated for cosmetic repairs and removal of excess frost. The identified deficiencies were attributed to maintenance activities and were not age-related with the exception of minor rusting on blanket fasteners, which did not result in any loss of intended function.

On the basis of the operating experience and root causes identified for corrective work, the staff concludes that the aging management activities described above have been effective at maintaining the intended function of the ice condenser system and reasonably can be expected to do so through the period of extended operation.

FSAR Supplement: In Appendix A-1, Section 18.2.14, and Appendix A-2, Section 18.2.13, of the LRA, the applicant described the Ice Condenser Engineering Program for McGuire and Catawba, respectively. The staff reviewed this information and found it to be consistent with the information provided in the LRA. No FSAR Supplement was provided for the Ice Basket Inspection because this activity is described in the TS. The staff finds the TS has sufficient information to be an acceptable summary description of the AMP.

In conclusion, the staff reviewed the information provided in Section B.3.18 of the LRA, and the summary description in the FSAR Supplement in Appendix A of the LRA. On the basis of its review and the above evaluation, the staff finds that the applicant has demonstrated that the effect of aging associated with the ice condenser structures will be adequately managed such that there is reasonable assurance that the intended function will be maintained in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Divider Barrier Seal Inspection and Testing Program</u>

Section B.3.11 of the LRA provides the description of the divider barrier seal inspection and testing activities. The applicant credits these activities for managing the aging effects of cracking and change of material properties of the elastomeric seals in the divider barrier inside containment. The staff reviewed Section B.3.11 of the LRA to determine whether the applicant had demonstrated that divider barrier seal inspection and testing activities will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

Section B.3.11 of the LRA describes the inspection and testing activities for the divider barrier seals. The divider barrier is the physical boundary that separates upper containment from lower containment. Several reactor building internal structures comprise the divider barrier and, as part of the divider barrier, elastomeric pressure seals are provided at locations where it is necessary to limit potential ice condenser bypass leakage. The purpose of the program is to manage the aging effects of cracking and change in material properties of the elastomeric seals for the period of extended operation. The program includes the following elastomeric seals:

- ice condenser seals,
- control rod drive mechanism shield seals,
- operating deck hatches and access opening seals,
- pressurizer enclosure seals,
- reactor coolant pump hatch seals,
- steam generator enclosure seals.

For both McGuire and Catawba, the testing is performed in accordance with TSSR 3.6.14.2, SR 3.6.14.4, and SR 3.6.14.5.

The applicant concluded that the continued implementation of the Divider Barrier Seal Inspection and Testing Program will manage the identified aging effects such that the seals will continue to perform their intended functions consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff's evaluation of the Divider Barrier Seal Inspection and Testing Program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site work management system. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] The scope of the program includes the following elastomeric seals:

- ice condenser seals,
- control rod drive mechanism shield seals,
- operating deck hatches and access opening seals,
- pressurizer enclosure seals,
- reactor coolant pump hatch seals,
- steam generator enclosure seals.

The applicant has included all the seals in the scope of this program which are essential for ensuring the separation of upper containment from lower containment. The staff considers the scope acceptable.

[Preventive Actions] There are no preventative actions taken as part of this program, and the staff did not identify the need for any preventative actions.

[Parameters Monitored or Inspected] The program monitors for cracking and change in material properties of elastomeric pressure seals. As the elastomeric seal can crack or change its properties as a result of aging, sustained high temperatures or radiation effects, the staff considers the parameters monitored or inspected reasonable and acceptable.

[Detection of Aging Effects] Section B.3.11 of the LRA states that cracking and change in material properties of elastomeric seals is detected through visual examinations and coupon testing. The testing is performed in accordance with Technical Specification SR 3.6.14.2, SR 3.6.14.4, and SR 3.6.14.5. Since cracking and change in material property can be detected by visual examination and coupon testing, and since the testing is in accordance with the TS, the staff finds this acceptable.

[Monitoring and Trending] Section B.3.11 of the LRA provides the following information:

> The Divider Barrier Seal Inspection and Testing Program detects aging effects through visual examination of the seals and coupon testing. The inspections and testing are implemented as required by McGuire and Catawba TS (SR) 3.6.14.2, 3.6.14.4 and 3.6.14.5.

> The ice condenser seals are visually inspected for the presence of holes, ruptures, abrasions, splice separation or gap, and changes in physical appearances such as discoloration, chemical attack, radiation damage, etc. At least 95 percent of the ice condenser seal is inspected. In addition, the seal mounting hardware is examined for looseness and loss of material due to corrosion. Two seal coupons are removed and tested to verify the tensile strength of the material. The frequency of the inspection of seals and tests of the coupons is once every 18 months as required by Technical Specification Surveillance Requirements 3.6.14.4 and 3.6.14.5.
>
> The remaining divider barrier seals are visually inspected for cracks, defects in the sealing surface, deterioration of the seal material, and detrimental misalignments. The frequency of the inspection is prior to final closure after each opening and once every 10 years for resilient seals as required by Technical Specification Surveillance Requirement 3.6.14.2.

The monitoring and trending for inspection and testing of the seals are in accordance with the Technical Specification surveillance requirements. The staff finds the extent of examination included for monitoring and trending reasonable and acceptable.

[Acceptance Criteria] Section B.3.11 of the LRA provides the following information:

> The acceptance criteria for the Divider Barrier Seal Inspection and Testing Program are specified in Technical Specification Surveillance Requirements 3.6.14.2, 3.6.14.4 and 3.6.14.5. The minimum tensile strength of both test coupons is specified in Technical Specification 3.6.14.4. The acceptance criteria for the visual inspection are no visual evidence of deterioration due to holes, ruptures, chemical attack, abrasion, radiation damage, or change in physical appearance. Divider barrier seal mounting hardware (i.e. bolts, nuts etc.) must be properly installed, with no unacceptable indication of corrosion.

The staff considers the acceptance criteria associated with this program reasonable and adequate.

[Operating Experience] The operating experience at McGuire and Catawba has not identified any adverse aging conditions of the divider barrier seals, such as cracking or change in material properties. Past coupon tests at both stations indicated tensile strength above that specified in SR 3.6.14.4, with sufficient margin. The staff finds that the described operating experience indicates that the program will adequately monitor the aging of the divider barrier seals.

FSAR Supplement: The essential requirements for this aging management program are stated in the Technical Specification Bases for SR 3.6.14.2, SR 3.6.14.4, and SR 3.6.14.5. The applicant did not provide a description in the FSAR Supplement, and the staff does not see a need for one.

In conclusion, the staff reviewed the information provided in Section B.3.11 of the LRA. On the basis of its review and the above evaluation, the staff finds that the applicant has demonstrated that the effect of aging associated with divider barrier seals will be adequately managed so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Technical Specification SR 3.6.16.3 Visual Inspection</u>

The applicant has identified change in material property due to leaching as an aging effect requiring programmatic management for the walls and dome of the concrete reactor building for the period of extended operation. The applicant credits the Technical Specification Surveillance Requirement (SR) 3.6.16.3 Visual Inspection program, discussed in Section B.3.33 of the LRA, with managing this aging effect. SR 3.6.16.3 requires that the applicant perform a visual inspection on the exposed interior and exterior surfaces of the reactor building three times every ten years. The purpose of the visual inspections is to uncover evidence of deterioration which could affect the reactor building structural integrity. The staff reviewed Section B.3.33 of the LRA to determine whether the applicant had demonstrated that the effects of aging will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

Section B.3.33 of the LRA provides a discussion of the program requirements for the Technical Specification SR 3.6.16.3 Visual Inspection. The purpose of the program is to manage the aging effect of leaching in the walls and dome of the concrete reactor building. SR 3.6.16.3 requires that the applicant perform a visual inspection on the exposed interior and exterior surfaces of the reactor building three times every ten years to identify deterioration which could affect the reactor building structural integrity.

The staff's evaluation of the Technical Specification SR 3.6.16.3 Visual Inspection program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site TS. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] The applicant described the scope of the Technical Specification SR 3.6.16.3 Visual Examination as including the accessible surface areas of the walls and dome of the concrete reactor building. The staff finds the scope acceptable because it is comprehensive and includes the areas of the reactor building walls and dome appropriate to identify the aging effects.

[Preventive Or Mitigative Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation, and the staff did not identify the need for any preventive actions.

[Parameters Monitored Or Inspected] The applicant identified the monitored parameter as the change in material property due to leaching. The staff agrees that because the visual inspections can detect property changes due to leaching, this is a proper parameter to identify potential degradation.

[Detection Of Aging Effects] The applicant stated that the Technical Specification SR 3.6.16.3 Visual Inspection program uses visual examination techniques to detect change in material properties due to leaching prior to loss of structure intended function. Because the inspections are current industry practice and have demonstrated the ability to detect changes, the staff finds that the inspection is capable of detecting the change and is acceptable.

[Monitoring And Trending] Section B.3.33 of the LRA states that loss of material due to leaching will be detected through the visual examination conducted as a part of the SR 3.6.16.3. This surveillance requirement provides advance indication of deterioration of the concrete structural integrity of the reactor building. The frequency of the inspection is three times every ten years. SR 3.6.16.3 does not include a requirement to monitor or trend degradation. If unacceptable conditions are noted in the inspection, the applicant performs further evaluation as appropriate.

By letter dated January 28, 2002, the staff requested, in RAI B.3.33-1, additional information related to the applicant's methods of inspecting the higher elevations of the reactor building. In its response dated March 11, 2002, the applicant stated that the containment vessel stiffening rings, located at ten-foot intervals along the exterior of the steel containment vessel, act as a platform for the inspectors, and that ladders and binoculars are used to inspect the exterior of the reactor building walls.

The staff finds, based on a review of the application and the applicant's response to the staff's RAI, that the monitoring is capable of identifying potential problems before they can result in loss of intended function. The staff did not identify a need for trending.

[Acceptance Criteria] The applicant stated that the acceptance criteria are based on visual indication of structural damage or degradation. For concrete, the acceptance criterion is no unacceptable indication of change in material property due to leaching. The Staff concludes that, because the inspection methods are capable of detecting deterioration, the acceptance criteria are appropriate.

[Operating Experience] The applicant reported that the SR 3.6.16.3 visual inspections have been performed at the specified frequencies since initial operation at McGuire and Catawba, and the results are documented in station procedures. The applicant further notes that the inspections have revealed only minor degradation of concrete at McGuire and Catawba. Observations include minor hairline surface cracking and minor leaching. The applicant reported that leaching has been observed on the interior of the reactor building domes at McGuire near the dome-to-shell interface, and the applicant has planned maintenance for the dome exterior to minimize water intrusion. Adverse conditions are reinspected by the applicant during subsequent inspections. The applicant notes that the observed aging effects are relatively minor and have no impact on the ability of the concrete reactor building to perform its intended function.

By letter dated January 28, 2002, the staff requested, in RAI 3.5-2, the applicant to provide the extent of the degradation observed. In its response dated March 11, 2002, the applicant provided further information regarding the minor degradation discussed above. Previous inspections had revealed changes in material properties due to leaching on the shield building dome and near the dome-to-shell interface at McGuire. Subsequent inspection did not indicate any growth of the leaching or rebar corrosion. Rebar corrosion would be evidenced by rust stains, pop-outs or spalling. The applicant further stated that the maintenance on the exterior of the shield building dome was completed in the fall of 2001. The domes were recoated with elastomeric urethane 18" up the parapet wall and 18" up the dome. The remainder of the dome was sealed with a clear concrete sealer. The applicant stated that subsequent inspections will determine whether the corrective actions are adequate and whether any additional maintenance is required. The staff finds the applicant's maintenance work and commitment to perform future inspections adequate and reasonable and, therefore, RAI 3.5-2 is resolved.

A review of the operating experience indicates that the inspections have been effective at identifying degradation and allowing the applicant to take corrective action. This provides reasonable assurance the inspections will continue to identify potential problems through the period of extended operation.

FSAR Supplement: The LRA does not provide a FSAR Supplement for the Technical Specification SR 3.6.16.3 Visual Inspection program. Since it is an existing program that is adequately described in the TS, the staff finds this acceptable.

In conclusion, the staff reviewed the information provided in Section B.3.33 of the LRA, the TS, and the applicant's March 11, 2002, responses to the staff's RAI. On the basis of its review and the above evaluation, the staff finds that there is reasonable assurance that the aging effect of leaching of the concrete reactor building will be adequately managed such that the intended function will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.1.3 Conclusions

The staff reviewed the information in Section 3.5.1 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of its review, with the exception of open items 3.5-1, 3.5-2, and 3.5-3, the staff finds that the applicant has demonstrated that the aging effects associated with the reactor building structural members will be adequately managed so that there is reasonable assurance that these structural components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2 Other Structures

3.5.2.1 Technical Information in the Application

The aging management review results for structures outside the reactor building are presented in Table 3.5-2 of the LRA. Table 3.5-2 of the LRA is divided into three sections covering (1) concrete structural components, (2) steel structural components, and (3) other structural components. In addition, Table 3.5-2 of the LRA identifies the components that constitute the other structures along with the component (1) function, (2) material, (3) environment, (4) aging effects, and (5) aging management programs and activities.

The aging management review results for structural components located within the following structures are provided in Table 3.5-2 of the LRA:

- auxiliary building
- condenser cooling water intake structure
- nuclear service water structures

- standby nuclear service water pond dam
- standby shutdown facility
- turbine buildings
- unit vent stack
- yard structures

The materials of construction for the components of the structures outside the reactor building, which are subject to aging management review, are (1) concrete, (2) steel, (3) boraflex, (4) silicone, (5) soil, (6) rubber, (7) masonry, (8) aluminum, and (9) a composite roofing material.

The components of the structures outside the reactor building are exposed to external, sheltered, below grade, raw water, and borated water environments. In addition, the components in Table 3.5-2 of the LRA include steel anchorages, embedments, and foundation dowels encased in concrete.

3.5.2.1.1 Aging Effects

Table 3.5-2 of the LRA identifies the following applicable aging effects for components in structures outside the reactor building:

- cracking of concrete fire walls in a sheltered environment
- cracking and loss of material for concrete components exposed to raw water
- change in material properties for some concrete components exposed to an external environment
- loss of material for carbon steel components in sheltered, raw water, and external environments
- loss of material and cracking for stainless steel components in borated water and raw water
- degradation due to gamma irradiation for boraflex panels in borated water
- loss of material and cracking of soil earthen embankments
- cracking and separation of silicone fire barrier penetration seals
- cracking of rubber fire barrier penetration seals
- cracking and change in material properties of rubber and silicone flood seals
- cracking of masonry block walls
- loss of material of composite roofing material

3.5.2.1.2 Aging Management Programs

Table 3.5-2 of the LRA credits the following aging management programs with managing the identified aging effects for the components in structures outside the reactor building:

- Boraflex Monitoring Program
- Flood Barrier Inspection Program
- Standby Nuclear Service Water Pond Dam Inspection
- Fire Protection Program
- Inspection Program for Civil Engineering Structures and Components
- Underwater Inspection of Nuclear Service Water Structures
- Fluid Leak Management Program
- Chemistry Control Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in structures outside the reactor building will be adequately managed by these aging management programs during the period of extended operation.

3.5.2.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures" and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the components in structures outside the reactor building have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management programs credited for the aging management of the components in structures outside the reactor building at McGuire and Catawba nuclear stations. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the components in structures outside the reactor building.

3.5.2.2.1 Aging Effects

Section 3.5.2 of the LRA provides an aging management review of the components in structures outside the reactor building. Table 3.5-2 of the LRA is divided into four sections: (1) concrete structural components, (2) steel structural components, and (3) other structural components. The staff's evaluation of the applicant's aging management review for these components follows.

<u>Concrete</u>
The applicant identified change in material properties as an applicable aging effect for reinforced concrete beams, columns, floor and roof slabs, and walls that are exposed to an external environment. In addition, the applicant identified change in material properties as an applicable aging effect for the refueling water storage tank missile shield wall. The applicant also identified loss of material and cracking as applicable aging effects for concrete exposed to a raw water environment. Cracking is also identified as an applicable aging effect for the concrete fire walls, which are in a sheltered environment.

As noted above in Section 3.5.1.2.1, the staff considers loss of material, cracking, and change in material properties to be both plausible and applicable aging effects for all concrete components, including masonry block walls, in all of the environments listed by the applicant. The staff noted that Table 3.5-2 of the LRA identifies an applicable aging effect (change in material properties) only for the refueling water storage tank missile shield wall and not for the other missile shield walls. By letter dated January 28, 2002, the staff requested, in RAI 3.5-8, the applicant to explain why loss of material, cracking, and change in material properties had not been identified as applicable aging effects for the other missile shield walls. In addition, the staff requested, in RAI 3.5-7, that the applicant identify the aging management program(s) that will be used to manage the aging effects for the many other concrete components in Table 3.5-2 for which no aging effects are identified. In its response dated March 11, 2002, the applicant stated that the concrete components listed in Table 3.5-2 were designed using the appropriate ACI and ASTM standards, which resulted in dense concrete with a suitable cement content that has been well cured and is less susceptible to calcium hydroxide loss (leaching). In addition, the applicant stated that operating experience to date has not shown any significant degradation of the concrete components listed in Table 3.5-2 of the LRA, for which no aging effects are identified. Therefore, with a few exceptions, only concrete components exposed to raw water and external environments have applicable aging effects that require aging management during the period of extended operation.

As stated earlier in Section 3.5.1.2.1, the staff considers that sound material design and construction together with sound inspection programs are both necessary to maintain the serviceability of concrete nuclear structures. Periodic visual inspections (1) can provide significant quantitative and qualitative data regarding structural performance and extent of degradation; (2) are vital to monitor the effects of operating and environmental conditions; and (3) enable the timely identification and correction of degraded conditions. In conclusion, periodic inspections of concrete components during the period of extended operation are necessary in order for the staff to make a reasonable assurance finding that in-scope concrete structures and components will maintain their structural integrity and intended function(s). Periodic visual inspections of concrete nuclear structures are a vital part of the license renewal program. On this basis, the staff disputes the applicant’s claim, in response to RAIs 3.5-7 and 3.5-8, that aging management programs are necessary only for the above-grade concrete components, listed in Tables 3.5-1 and 3.5-2 of the LRA, that are exposed to harsh environments. This issue is identified in Section 3.5.1.2.1 as open item 3.5-1.

For below-grade concrete components listed in Table 3.5-2 of the LRA, the staff has determined that aging management is unnecessary if applicants are able to show that the below grade soil/groundwater environment is non-aggressive. In RAI 3.5-1, the staff requested that the applicant provide further information regarding the chemistry of the groundwater samples taken at both Catawba and McGuire nuclear stations. The applicant’s response to RAI 3.5-1 is discussed in more detail above in Section 3.5.1.2.1. Briefly, the applicant showed that the chloride, sulfate, and pH values over the past 20 to 30 years are well below the limits where potential degradation of concrete may occur. Therefore, aging management of below-grade concrete components, listed in Table 3.5-2 of the LRA, during the period of extended operation is unnecessary. However, the applicant does not commit, in its response to RAI 3.5-1, to further monitor the groundwater or to initiate corrective action in the event of a chemical release during the period of extended operation. This is identified in Section 3.5.1.2.1 as open item 3.5-2.

<u>Steel</u>
Table 3.5-2 of the LRA identifies (1) loss of material for carbon steel components in sheltered, raw water, and external environments and (2) loss of material and cracking for stainless steel components in borated water and raw water as applicable aging effects for the steel components in structures outside the reactor building. The staff finds that the applicant’s approach for evaluating the applicable aging effects for the steel components in structures outside the reactor building to be reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effects for steel components in these structures.

Other Materials: Table 3.5-2 of the LRA identifies the following aging effects for other material components (besides concrete and steel) in structures outside the reactor building:

- degradation due to gamma irradiation for boraflex panels in borated water
- loss of material and cracking of soil earthen embankments
- cracking and separation of silicone fire barrier penetration seals
- cracking of rubber fire barrier penetration seals
- cracking and change in material properties of rubber and silicone flood seals
- loss of material of composite roofing material

The staff finds that the applicant's approach for evaluating the applicable aging effects for the other material components in structures outside the reactor building to be reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effects for the other material components in these structures.

3.5.2.2.2 Aging Management Programs

Table 3.5-2 of the LRA credits the following aging management programs with managing the identified aging effects for the components in structures outside the reactor building:

- Boraflex Monitoring Program
- Flood Barrier Inspection Program
- Standby Nuclear Service Water Pond Dam Inspection
- Fire Protection Program
- Inspection Program for Civil Engineering Structures and Components
- Underwater Inspection of Nuclear Service Water Structures
- Fluid Leak Management Program
- Chemistry Control Program

The latter five aging management programs listed above (Fire Protection Program, Inspection Program for Civil Engineering Structures and Components, Underwater Inspection of Nuclear Service Water Structures, Fluid Leak Management Program, Chemistry Control Program) are credited with managing the aging of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for the components in structures outside the reactor building. The staff's review of the common aging management programs is documented in Section 3.0 of the SER. The staff's evaluation of the Boraflex Monitoring Program, Flood Barrier Inspection Program, and Standby Nuclear Service Water Pond Dam Inspection aging management programs follows:

<u>Boraflex Monitoring Program</u>

The applicant described its boraflex monitoring program in Section B.3.3, of Appendix B of the LRA. The staff reviewed the application to determine whether the applicant had demonstrated that the boraflex surveillance program will adequately manage the applicable effects of aging in the plants during the period of extended operation as required by 10 CFR 54.21(a)(3).

The boraflex monitoring program, applicable only to McGuire, is credited for managing the aging of boraflex panels for the period of extended operation. The boraflex monitoring program is a performance monitoring program that manages the degradation of the panels in the spent fuel storage racks due to gamma irradiation. The boraflex panels ensure that the reactivity of the storage fuel assemblies is maintained within required limits. In addition, the applicant references the McGuire SLC 16.9.24, “Spent Fuel Pool Storage Rack Poison Material,” which contains additional information related to the management of the boraflex panels.

The staff’s evaluation of the boraflex monitoring program focused on how the program managed aging effects through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program. The staff’s evaluation of the applicant’s quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] The boraflex monitoring program includes all boraflex neutron-absorbing panels in the McGuire ½ spent fuel storage racks. The staff agrees that it is appropriate to include this material component within the scope of the boraflex monitoring program.

[Preventive or Mitigative Actions] The boraflex monitoring program has no associated preventive or mitigative actions. The staff concludes that there are no preventive or mitigative actions to prevent the further break down of the polymer matrix and eventual release of boron carbide into the SFP. However, based on the known mechanism governing the polymer matrix breakdown, the staff requested information related to the SFP cleanup system and any steps taken to limit the disturbance of the quiescent state of the spent fuel pool. In a conference call on August 21, 2001, the applicant clarified for the staff that the SFP cleanup system is run continuously. In addition, the demineralizer efficiency of silica removal is one percent. The applicant also stated that their predictive model of boraflex degradation accounts for the continuous operation of the SFP cleanup system. This clarifying information is documented in a conference call summary dated September 10, 2001. The staff finds that this clarifying information does not adversely impact the aforementioned conclusion.

[Parameters Monitored or Inspected] The boraflex monitoring program monitors the boraflex panel average storage rack poison material by measuring the Boron-10 areal density. The panel average Boron-10 areal density is used as an input to the spent fuel pool storage rack criticality calculations. In addition, the silica levels are monitored in the spent fuel pool which provide an indication of the depletion of boron carbide from boraflex. The staff finds that the parameters inspected and monitored under this program are appropriate and adequate to determine degradation of the boraflex panels in the spent fuel racks.

[Detection of Aging Effects] The boraflex monitoring program will monitor boraflex panel areal density prior to loss of intended function. The staff finds that this testing parameter, in conjunction with silica concentration monitoring, is effective and adequate in detecting the aging effects associated with degradation of the boraflex panels.

[Monitoring and Trending] The boraflex monitoring program includes in-situ testing of the Boron-10 areal density at a frequency of every three years. The applicant further stated that testing may be performed more frequently based on engineering judgment, spent fuel pool water chemistry, and modeling projections of boraflex degradation. Selection of boraflex panels for in-situ testing is based on predicted Boron-10 areal density loss. The staff finds that it is appropriate and prudent to monitor and trend density changes of the boraflex panels.

[Acceptance Criteria] The acceptance criteria for the boraflex monitoring program is based on maintaining the minimum areal density of boron carbide assumed in the criticality calculations. These requirements are provided in the McGuire SLC 16.9.24, “Spent Fuel Pool Storage Rack Poison Material.” The staff agrees that the acceptability of boraflex degradation should be controlled by the assumptions in the criticality analysis and, based on the requirements provided in SLC 16.9.24, concludes that this program has appropriate acceptance criteria to ensure that the boraflex panels continue to meet their intended function.

[Operating Experience] The application stated blackness testing was performed at McGuire in 1991. This testing measured shrinkage as well as size and frequency of gap formation. The data obtained from this testing was incorporated into the revised criticality analyses discussed in Reference B-7 of the LRA. As a result of NRC issued Generic Letter 96-04, “Boraflex Degradation in Spent Fuel Pool Storage Racks,” the applicant provided two responses as discussed in References B-7 and B-9 of the LRA. The applicant stated that the responses to GL 96-04 indicate that the EPRI RACKLIFE computer code had been acquired to assess overall boraflex thinning based on cumulative gamma exposure, storage rack design parameters, and dissolved silica concentration in the spent fuel pool. In addition, the applicant stated that in-situ measurements were performed that verified that this monitoring program accurately predicts the Boron 10 areal density.

The staff has reviewed SLC 16.9.24 and its basis; i.e., the staff’s Safety Evaluation to Amendment No. 197 to Facility Operating License NPF-9 and Amendment No. 178 to Facility Operating License NPF-17 transmitted by NRC letter dated November 27, 2000. The SLC is designed to ensure that an unplanned criticality event cannot occur as a result of degraded boraflex conditions. In a conference call on August 21, 2001, the applicant confirmed for the staff that the measured boraflex degradations were within the limits imposed by the SLC. In addition, the applicant clarified that although the RACKLIFE predictive code had not been used to project boraflex degradation in the period of extended operation, the applicant has initiated activities to remediate anticipated unacceptable loss of boraflex. This clarifying information is documented in the conference call summary dated September 10, 2001.

Based on the details of the operating experience in this program, the staff finds that this program will continue to address the boraflex degradation at McGuire.

FSAR Supplement: The McGuire SLC program constitutes Chapter 16 of the McGuire UFSAR and its contents are maintained in a separate manual. The boraflex monitoring program is a current program with requirements found in SLC 16.9.24. The staff has reviewed SLC 16.9.24 and finds that it contains the appropriate elements of this program.

In conclusion, the staff has reviewed the boraflex monitoring program in Section 3.3 of Appendix B of the LRA. On the basis of its review and the above evaluation, the staff finds that the applicant has demonstrated that the effects of aging associated with the boraflex monitoring program will be adequately managed so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Flood Barrier Inspection

The applicant described its Flood Barrier Inspection program in Section B.3.13 of the LRA. The applicant credits this program for managing the aging effects associated with the elastomeric flood seals that protect equipment such that no safety-related intended functions or safe shutdown capabilities are adversely impacted. This program is only used for McGuire; at Catawba the flood barriers are inspected as part of the inspection program for civil engineering structures and components. The staff reviewed Section B.3.13 of the LRA to determine whether the applicant had demonstrated that flood barrier inspection activities will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

Section B.3.13 of the LRA states that the purpose of the flood barrier inspection activities is to manage aging effects of the elastomeric flood seals to ensure that safety-related equipment is protected from floods and flooding flow paths, such that no equipment safety-related intended functions or station safe shutdown capabilities are adversely impacted. The applicant stated that this is a condition monitoring program that applies only to McGuire. The flood barriers at Catawba are inspected as part of the inspection program for civil engineering structures and components. Cracking and change in material properties of flood seals are identified as aging effects that require monitoring for the period of extended operation. This program was initiated in response to NRC Information Notice 87-49, “Deficiencies in Outside Containment Flooding Protection,” to ensure that flood protection features outside containment are properly installed and maintained. This program monitors the cracking and separation of the internal elastomeric flood seals. Structures and components that do not meet the acceptance criteria are evaluated for continued service and repaired as required. Corrective actions and confirmatory actions, as needed, are implemented in accordance with the corrective action program.

The staff’s evaluation of the flood barrier inspection activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site work management system. The staff’s evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] Section B.3.13 of the LRA identifies the scope as the internal elastomeric flood seals outside containment that protect equipment from floods and flood flow paths such that no equipment safety-related intended functions or station safe shutdown capabilities are adversely impacted. This program is only applicable to McGuire; at Catawba the fire barrier seals inspections are implemented through the inspection program for civil engineering structures and components. This is acceptable to the staff.

[Preventative Actions] There are no preventative actions taken as part of this program, and the staff did not identify the need for any preventative actions.

[Parameters Monitored or Inspected] Section B.3.13 of the LRA identifies cracking and change in material properties that would challenge the function of the flood barrier seals as the parameters that can be detected by visual inspection. Because visual inspection can be used to identify the degraded conditions noted by the applicant, such inspections of the flood barriers are acceptable to the staff.

[Detection of Aging Effects] Section B.3.13 of the LRA states that visual inspection will detect cracking and change in material properties of elastomeric flood seals prior to the loss of structure or component intended functions. The use of visual inspection of the external condition of elastomeric seals is considered by the staff to be a reasonable means of detecting cracking and change in material properties before the loss of intended function.

[Monitoring and Trending] Section B.3.13 of the LRA states that the flood seals are inspected by visual inspection at a frequency of 18 months. No actions are taken as part of the program to trend the inspection results. Since structures and components that do not meet the acceptance criteria are evaluated for continued service and repaired as required, and since corrective actions and confirmatory actions, as needed, are implemented in accordance with the corrective action program, the staff finds this acceptable.

[Acceptance Criteria] Section B.3.13 of the LRA states that the acceptance criteria is no unacceptable visual indications of cracking and change in material properties that would result in loss of intended function. The assessment of the severity of the observed degradation and determination of whether corrective action is necessary is based on the judgement of the inspector. By letter dated January 28, 2002, the staff requested, in RAI B.3.13-1, the applicant to describe the criteria for (1) assessing the severity of the observed degradations and (2) determining whether corrective action is necessary. In its response dated March 11, 2002, the applicant stated that McGuire management assigns the personnel who perform the inspection of the flood barriers. The individuals are chosen based on education and work experience to ensure that they are well-qualified. The inspector visually examines the flood seals for cracking and change in material properties that would result in loss of the intended function of the seal. The assessment of the severity of the observed degradation and the determination of whether corrective action is necessary are based on the judgment of the inspector. If the inspector identifies degradation that would lead to loss of intended function, a corrective action report will be initiated. The corrective action process is a formalized process, in accordance with 10 CFR Part 50, Appendix B, quality assurance requirements, for documenting engineering evaluations of plant problems and would include the assessment of the severity of the observed degradation, the need for corrective actions, the need for further inspections of other locations, and the need for future inspections or programmatic oversight. The staff finds that, because the acceptance criteria are consistent with the degradation of concern, which is detectable by visual inspections, and because the inspections and evaluations will be conducted by knowledgeable and experienced individuals, the applicant’s response is acceptable.

[Operating Experience] Section B.3.13 of the LRA describes the plant-specific operating experience related to the inspections of the flood barrier seals. The inspections have resulted in repairs for a variety of reasons to ensure that the intended functions continue to be met. From this the applicant concludes that the program had been demonstrated to be effective in managing cracking and change in material properties of the elastomeric flood seals. The staff concurs that the program as described and the inspection frequency provide reasonable assurance that the intended function of the flood seals will continue to be met.

FSAR Supplement: The staff reviewed Appendix A of the LRA, Section 18.2.9 the FSAR Supplement for McGuire. The FSAR Supplement indicates that the program includes periodic visual inspections of the flood seals to identify degradation that could result in loss of the intended functions of the flood seals. The staff finds that the description of the applicant's flood barrier seal inspection activities is consistent with Section B.3.13 of the LRA and, therefore, acceptable.

In conclusion, the staff reviewed the information provided in Section B.3.13 of the LRA and the summary description of the flood barrier seal inspection activities in Appendix A of the LRA, Section 18.2.9 the FSAR Supplement for McGuire. In addition, the staff considered the applicant's March 11, 2002, response to the staff's RAI. On the basis of its review and the above evaluation, the staff finds that the aging effects of the flood barrier seals will be adequately managed such that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Standby Nuclear Service Water Pond Dam Inspection

The applicant described its standby nuclear service water pond (SNSWP) dam inspection activities in Section B.3.30 of the LRA. The applicant credits this inspection activity with managing the potential aging of the SNSWP dams. The staff reviewed Section B.3.30 of the LRA to determine whether the applicant had demonstrated that SNSWP dam inspection activities will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

Section B.3.30 of the LRA states that the purpose of the SNSWP dam inspection activities is to provide reasonable assurance that the effects of aging will be managed so that the intended function of the SNSWP will be maintained consistent with the CLB during the period of extended operation. Loss of material and cracking of earthen embankments have been identified as aging effects requiring management for the SNSWP dam for the period of extended operation. The Standby Nuclear Service Water Pond Dam Inspection program is credited with managing these aging effects. The scope of the program includes the upstream and downstream slopes, the spillway overflow/outlet works, the area near the right and left abutments, and the toe of the dam. A visual examination is performed for erosion, settlement, slope stability, seepage, drainage systems, integrity of rip-rap, and environmental conditions. The inspections are performed on an annual basis as required by McGuire Technical Specification Surveillance Requirement (SR) 3.7.8.3 and Catawba Technical Specification SR 3.7.9.3. In addition, the results of the piezometric readings and settlement monitoring are reviewed. Piezometers are located on the dam to monitor foundation pore pressure. The piezometers are read quarterly. Survey monuments are located on the crest along the entire length of the dam to provide information on settlement. Surveys of the monuments are performed annually. The inspections are performed in accordance with the guidance in Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants."

The applicant stated that acceptance criteria are the absence of visual indications of abnormal degradation, vegetation growth, erosion, or excessive seepage that would affect the SNSWP dam operability. Structures and components which do not meet the acceptance criteria are evaluated by the "accountable engineer" for continued service, and repaired as required. Each inspection records the recommendations concerning repairs or studies. Structures and components which are deemed unacceptable are documented under the corrective action program. Specific corrective actions and confirmatory actions, as needed, are implemented in accordance with the corrective action program.

The applicant's operating experience, described in the LRA, shows that no conditions have been observed which have adverse effects on the intended function of the SNSWP dam at McGuire or Catawba. Corrective action programs at both sites effectively take care of minor maintenance activities.

The staff's evaluation of the Standby Nuclear Service Water Pond Dam Inspection focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site TS. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] Section B.3.30 of the LRA identifies the scope as the SNSWP dam, including the upstream and downstream slopes, the spillway overflow/outlet works, the area near the right and left abutments, and the toe of the dam. This is acceptable to the staff.

[Preventative Actions] There are no preventative actions taken as part of this program, and the staff did not identify the need for any preventative actions.

[Parameters Monitored or Inspected] Section B.3.30 of the LRA states that the examination guidelines are in accordance with RG 1.127. The dam is visually examined for erosion, settlement, slope stability, seepage, drainage systems, integrity of rip-rap, and environmental conditions. In addition, the results of the piezometric readings of foundation core pressure and survey monument readings of settlement are reviewed. The applicant's March 11, 2002, response to the staff's request for additional information states that, in accordance with RG 1.127, both faces of the dam are inspected for seepage, slides, erosion, abnormal degradation, and vegetative growth. Because these inspections can be used to identify the degraded conditions noted by the applicant, such inspections of the SNSWP dam are acceptable to the staff.

[Detection of Aging Effects] Section B.3.30 of the LRA states that visual inspection will detect cracking and loss of material of the SNSWP dam. The dam is visually examined for erosion, settlement, slope stability, seepage, drainage systems, integrity of rip-rap, and environmental conditions. In addition, the results of the piezometric readings of foundation core pressure and survey monument readings of settlement are reviewed. Both faces of the dam are inspected for seepage, slides, erosion, abnormal degradation, and vegetative growth. The above inspections provide an effective means of detecting cracking and loss of material of the SNSWP dam, and are acceptable to the staff.

[Monitoring and Trending] Section B.3.30 of the LRA states that the visual inspections are conducted annually, in accordance with the site TS, the piezometers are read quarterly, and the survey monuments are checked annually. Inspection reports are retained in sufficient detail to permit adequate confirmation of the inspection results. The records identify past inspection results, the results of the most recent inspection, whether the results were acceptable, discrepancies and their cause, and any corrective action resulting from the inspection. The applicant's March 11, 2002, response to the staff's request for additional information states that, if degradation is evident that would lead to the loss of intended function, an evaluation of the problems would be performed, including the need for further inspections of other locations. The staff finds that the monitoring and trending of SNSWP dam aging is effective and, therefore, acceptable.

[Acceptance Criteria] Section B.3.30 of the LRA states that the acceptance criteria is no unacceptable visual indications of abnormal degradation, vegetation growth, erosion, or excessive seepage that would affect the SNSWP dam operability. By letter dated January 28, 2002, the staff requested, in RAI B.3.30-3, the applicant to describe the acceptance criteria for (1) assessing the severity of the observed degradations, and (2) determining whether corrective action is necessary. In its response dated March 11, 2002, the applicant stated that the acceptance criteria follow the guidance provided in codes and standards, such as RG 1.127 and 18 CFR Part 12. The assessment of the severity of the observed degradation and the determination of whether corrective action is necessary is performed by the "accountable engineer." By letter dated January 28, 2002, the staff requested, in RAI B.3.30-2, additional information regarding the qualifications of the accountable engineer. In its March 11, 2002, response, the applicant stated that the accountable engineer is chosen based on education and work experience. It further stated that the accountable engineer qualifications are in accordance with RG 1.127. The accountable engineer should be a registered professional engineer experienced in the investigation, design, construction, and operation of dams. Because the acceptance criteria are consistent with the degradation of concern, which is detectable by visual inspections, and because the inspections and evaluations will be conducted by knowledgeable and experienced individuals, the staff finds the applicant's responses to these RAIs acceptable.

[Operating Experience] Section B.3.30 of the LRA describes the plant-specific operating experience related to the inspections of the flood barrier seals. The inspections have found the dams to be in good condition, with no conditions identified that would have adverse effects on the intended function of the dams. At McGuire, the most common recommendations were to spray the riprap on the upstream face and downstream toe of the dam to kill vegetation, repair ruts, and re-seed. Structurally, cracks found in the vicinity of the concrete drainage ditch have been cleaned out and sealed with appropriate sealer. At Catawba, the most common recommendations are to clear vegetation from the concrete drainage ditches, pack soil and gravel along the sides of the concrete drainage ditch, and monitor any signs of erosion along the sides of the concrete drainage ditch. Further, dam safety audits, performed by the NRC in 1994 and 1998 for McGuire, and in 1997 and 1999 for Catawba, concluded that there were no conditions that would indicate an immediate or adverse threat to the safety and permanence of the SNSWP dams. From this the applicant concludes that the program had been demonstrated to be effective in managing cracking and loss or material of the SNSWP dams and Catawba and McGuire. The staff concurs that the program as described and the inspection frequency provide reasonable assurance that the intended function of the flood seals will continue to be met.

FSAR Supplement: The applicant did not propose a FSAR Supplement for the SNSWP dam inspection activities. A summary description already exists in the bases section for Technical Specification SR 3.7.8.3. The staff reviewed the TS and finds the description consistent with Section B.3.30 of the LRA and, therefore, acceptable.

In conclusion, the staff reviewed the information provided in Section B.3.30 of the LRA and the summary description of the SNSWP dam inspection activities in the Technical Specification bases section. In addition, the staff considered the applicant's March 11, 2002, response to the staff's RAIs. On the basis of its review and the above evaluation, the staff finds that the aging effects of the SNSWP dam will be adequately managed such that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3 Conclusions

The staff reviewed the information in Section 3.5.2 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of its review, with the exception of open items 3.5-1 and 3.5-2, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in structures outside the reactor building will be adequately managed so that there is reasonable assurance that these structural components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.3 Component Supports

3.5.3.1 Technical Information in the Application

The aging management review results for component and equipment supports are presented in Table 3.5-3 of the LRA. Table 3.5-3 of the LRA identifies the component and equipment support (1) function, (2) material, (3) environment, (4) aging effects, and (5) aging management programs and activities.

Component supports are those components that provide support or enclosure for mechanical and electrical equipment. Component supports include battery racks, cable tray and conduit, cable tray and conduit supports, control boards, crane rails, enclosures, equipment component supports, HVAC duct supports, instrument line supports, instrument racks and frames, lead shielding supports, new fuel storage racks, pipe supports, stair, platform and grating supports, and spent fuel storage racks.

Also included within the scope of component supports are the Class 1, nuclear steam supply system (NSSS) supports. These Class 1 component supports include RCS piping supports, pressurizer upper and lower lateral supports, reactor vessel support, control rod drive seismic structure supports, steam generator vertical, lower lateral, and upper supports, and reactor coolant pump lateral and vertical support assemblies.

The materials of construction for the component supports, which are subject to AMR, are steel or stainless steel and are located in all of the structures within the scope of license renewal for McGuire and Catawba nuclear stations.

The component and equipment supports are exposed to internal (sheltered, reactor building), external, raw water, and borated water environments.

3.5.3.1.1 Aging Effects

Table 3.5-3 of the LRA identifies the following applicable aging effects for the component and equipment supports:

- loss of material for most steel components in sheltered or external environments
- cracking and loss of material for stainless steel spent fuel storage racks in borated water

3.5.3.1.2 Aging Management Programs

Table 3.5-3 of the LRA credits the following aging management programs with managing the identified aging effects for the component and equipment supports:

- Battery Rack Inspections
- Crane Inspection Programs
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- ISI Plan - Subsection IWF
- Underwater Inspection of Nuclear Service Water Structures
- Chemistry Control Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in the reactor building will be adequately managed by these aging management programs during the period of extended operation.

3.5.3.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, “Scoping and Screening Results: Structures” and the applicable aging management program and activity descriptions provided in Appendix B of the LRA to determine whether the aging effects for the component supports have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff’s evaluation of the applicant’s aging management review for aging effects and the applicant’s aging management programs credited for the aging management of the component supports at McGuire and Catawba nuclear stations. The staff’s evaluation includes a review of the aging effects considered and the basis for applicant’s elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the component supports.

3.5.3.2.1 Aging Effects

Each of the in-scope component supports listed in Table 3.5-3 are either steel or stainless steel components. For the stainless steel spent fuel storage racks exposed to borated water, Table 3.5-3 identifies cracking and loss of material as applicable aging effects. However, in Table 3.5-3 of the LRA, the applicant does not distinguish between carbon steel and galvanized steel components. For most of the steel component supports listed in Table 3.5-3, the applicant lists loss of material as an applicable aging effect. However, for some steel component supports no aging effects are identified. By letter dated January 28, 2002, the staff requested, in RAI 3.5-9, that the applicant state the type of steel used for the component supports, listed in Table 3.5-3 of the LRA, that do not have any applicable aging effects.

In its response, dates March 11, 2002, the applicant stated that metal housing systems, such as control boards, electrical and instrument panels, enclosures, etc. constructed of factory baked painted steel or galvanized sheet metal, do not have a tendency to age with time [Reference "An Aging Assessment of Relay and Circuit Breakers and System Interactions," prepared by Franklin Research Center for Brookhaven National Laboratory, NUREG/CR-4715, June 1987]. Industry operating experience with metal housing systems indicates that they have performed without failure to the present [References "Aging Management Guideline for Commercial Nuclear Power Plants - Motor Control Centers," SAND 93-7069, Sandia National Laboratories, February 1994 and "Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Switchgear," SAND 93-7027, Sandia National Laboratories, July 1993.]. Therefore, loss of material is not an aging effect requiring management for electrical panels, enclosures, and control boards in sheltered(reactor building) and external environments.

The applicant further states that the cable trays in the reactor building are constructed of painted or galvanized sheet metal similar to the metal housings and located in the same sheltered environment; therefore, the cable trays would age similarly to the metal housings. A review of industry operating experience was also implemented to validate this conclusion. Deficiencies that were identified were event driven or design/installation deficiencies. Therefore, loss of material is not an aging effect requiring management for cable trays in sheltered (reactor building) and external environments.

The applicant asserted that the new fuel storage racks provide dry storage for new nuclear fuel. These racks are free-standing and are designed to accommodate fuel assemblies. The storage racks are fabricated from painted carbon steel and are located in a mild dry sheltered environment. A review of operating experience did not identify any aging effects requiring management. Therefore, loss of material is not an aging effect requiring management for the new fuel storage racks.

The staff evaluated the above technical justifications and finds them reasonable and adequate in scope to support the aging management review results described in Table 3.5-3. The staff finds that the applicant's approach for evaluating the applicable aging effects for component supports as described in Table 3.5-3 reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effects for the component supports. The staff also concludes that the applicant has demonstrated that the aging effects for the component supports will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.3.2.2 Aging Management Programs

Table 3.5-3 of the LRA credits the following aging management programs with managing the identified aging effects for the component and equipment supports:

- Battery Rack Inspections
- Crane Inspection Programs
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- ISI Plan - Subsection IWF
- Underwater Inspection of Nuclear Service Water Structures
- Chemistry Control Program

The latter five aging management programs listed above (Fluid Leak Management Program, Inspection Program for Civil Engineering Structures and Components, ISI Plan - Subsection IWF, Underwater Inspection of Nuclear Service Water Structures, Chemistry Control Program) are credited with managing the aging of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for the component and equipment supports. The staff's review of the common aging management programs is documented in Section 3.0 of the SER. The staff's evaluation of the Battery Rack Inspections and the Crane Inspection Programs aging management programs follows:

<u>Battery Rack Inspections</u>

The applicant described the Battery Rack Inspections program in Section B.3.2 of the LRA. The applicant credits this program with managing the potential aging effect of loss of material of the battery racks. The staff reviewed Section B.3.2 of the LRA to determine whether the applicant had demonstrated that the battery rack inspection activities will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

Section B.3.2 of the LRA states that the purpose of the battery rack inspection activities is to provide reasonable assurance that the effects of aging will be managed such that the intended function of the battery racks is maintained through the period of extended operation. Section B.3.2 of the LRA identifies the loss of material due to corrosion as an aging effect requiring programmatic management for steel battery racks. The applicant stated that the battery rack inspection activities are credited with managing loss of material that could impact the intended function of structural support. The Battery Rack Inspections program covers the following four battery systems:

- EPL system (vital batteries)
- EPQ system (diesel generator batteries)
- ETM system (standby shutdown facility batteries)
- EQD system (standby shutdown facility diesel batteries)

The applicant stated that the regulatory basis for inspecting battery racks is found in the McGuire and Catawba TS and SLCs as identified in the following:

McGuire:

- EPL system - Technical Specification Surveillance Requirements (SR) 3.8.4.3
- EPQ system - SLC 16.8.3.3
- EQD system - SLC 16.9.7.12
- ETM system - SLC 16.9.7.17

Catawba:

- EPL system - TSSR 3.8.4.4
- EPQ system - TSSR 3.8.4.4
- EQD system - SLC 16.7-9.2
- ETM system - SLC 16.7-9.4

The applicant concluded that the continued implementation of the Battery Rack Inspections provides reasonable assurance that loss of material will be managed such that the intended functions of the battery racks will continue to be maintained consistent with the CLB for the period of extended operation.

The staff's evaluation of the battery rack inspection activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the TS and site procedures. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of program] The applicant states in the LRA that the scope of the Battery Rack Inspections includes the battery racks for the following systems:

- EPL system (vital batteries)
- EPQ system (diesel generator batteries)
- ETM system (standby shutdown facility batteries)
- EQD system (standby shutdown facility diesel batteries)

The staff finds that the scope of the Battery Rack Inspections is adequate because it includes inspections of the essential battery racks for the plant systems.

[Preventive Actions] There are no preventative actions taken as part of this program, and the staff did not identify the need for any preventative actions.

[Parameters Monitored or Inspected] The parameters inspected include the visual examination of the battery racks for physical damage or abnormal deterioration, including the loss of material. The staff finds this is acceptable for the inspection of battery racks. However, degraded anchorage of the battery racks may lead to loss of battery rack intended function. Consequently, by letter dated January 28, 2002, the staff requested, in RAI B.3.2-1, the applicant to provide a description of how the inspections of the battery rack anchorages will ensure that deterioration of the anchorages does not lead to a loss of function for the battery racks. In its response dated March 11, 2002, the applicant stated that the battery rack inspections use plant procedures to inspect for loss of material of the battery racks and all sub-components (including battery rack nuts, bolts, rails, supports, seismic brace, and anchor bolts). The battery rack inspections activities require visual examination of the battery racks, including sub-components, for physical damage or abnormal deterioration, including loss of material due to corrosion. The applicant further stated that the inspection acceptance criteria for loss of material in the procedure is “ No significant amount of corrosion or rust spots visible.” Physical damage or deterioration are evaluated to determine if the physical damage or deterioration affects the battery’s ability to perform its function. Since the inspections performed can detect degradation that would effect the intended function of the battery racks, the staff finds the applicant’s response acceptable.

[Detection of Aging Effects] The applicant stated that the battery rack visual inspections are performed every 18 months to detect loss of material in accordance with McGuire and Catawba TS and SLCs. Because visual inspection can be used to identify the degraded conditions noted by the applicant, such inspections of the battery racks are acceptable to the staff.

[Monitoring and Trending] Section B.3.2 of the LRA states that the visual inspections of the battery racks are performed every 18 months to detect loss of material in accordance with McGuire and Catawba TS and SLCs. The inspections are based on guidance provided in IEEE 450-1980 (Reference B-6 of the LRA). No actions are taken as part of this program to trend inspection results.

The staff finds that these monitoring activities are acceptable and agrees that no actions are needed as part of this program to trend inspection results.

[Acceptance Criteria] The applicant stated that the acceptance criterion is no visual indication of loss of material. However, it is not clear to what extent the loss of material is acceptable. Consequently, by letter dated January 28, 2002, the staff asked, in RAI B.3.2-1, the applicant to describe the criteria for (1) assessing the severity of the observed degradations, and (2) determining whether corrective action is necessary. In its response dated March 11, 2002, the applicant stated that the procedure acceptance criteria for loss of material is “no significant amount of corrosion or rust spots visible,” and that visual inspections for these types of degradation have been addressed in NRC Inspection Procedure 62002, “Inspection of Structures, Passive Components, and Civil Engineering Features at Nuclear Power Plants,” and NEI 96-03, “Industry Guideline for Monitoring Structures.” The staff finds these procedure guidelines acceptable for assessing the adequacy of the degraded battery racks including sub-components.

[Operating Experience] The applicant stated that a review of McGuire and Catawba-specific surveillance records did not identify any instances where abnormal deterioration, which would include loss of material, of the battery racks had occurred. The staff finds that the applicant’s operating experience indicates that the applicant’s battery rack inspection activities are effective in managing the aging effects of the battery racks.

FSAR Supplement: The staff reviewed Table 18-1 of Appendix A-1 and Appendix A-2 of the LRA for McGuire and Catawba, respectively, and compared them with Section B.3.2 of LRA. The staff finds that Table 18-1 referenced the proper sections of McGuire and Catawba TS and SLCs; however, neither the FSAR Supplement nor the referenced TS and SLCs provide adequate descriptions of the Battery Rack Inspections. The applicant is requested to provide a summary description characterizing the important elements of the Battery Rack Inspections from Section B.3.2 of the LRA and the applicant's response to RAI B.3.2-1, as described above. This issue is characterized as open item 3.5-4.

In conclusion, the staff reviewed the information provided in Section B.3.2 of the LRA and the applicant's March 11, 2002, response to the staff's RAI. On the basis of its review and the above evaluation, the staff finds that the applicant has demonstrated that the Battery Rack Inspections program will adequately manage the aging effects so that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Crane Inspection Program</u>

The applicant describes its crane inspection activities in Section B.3.10 of the LRA. The applicant credits this inspection activity with managing the potential aging of the cranes that are within the scope of license renewal. The staff reviewed Section B.3.10 of the LRA to determine whether the applicant had demonstrated that the crane inspection activities will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

Section B.3.10 of the LRA identifies the loss of material as an aging effect requiring management for crane rails and girders for the period of extended operation. The applicant stated that the purpose of the Crane Inspection Program is to manage loss of material for the steel rails and girders within the scope of license renewal. This program has been in effect for many years at the applicant's facilities and is based on the guidance contained in ANSI B30.2.0 (Reference B - 27 of the LRA) for cranes, ANSI B30.16 (Reference B - 28 of the LRA) for hoists, and the requirements contained in 29 CFR Chapter XVII, 1910.179 (Reference B - 29 of the LRA).

The applicant concluded that the continued implementation of the Crane Inspection Program provides reasonable assurance that loss of material will be detected and managed such that the intended function of the crane and hoist rails and girders will continue to be maintained consistent with the current licensing basis for the period of extended operation.

The staff's evaluation of the Crane Inspection Program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site work management system. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Program Scope] Section B.3.10 of the LRA states in the LRA that the scope of the Crane Inspection Program includes seismically restrained cranes. This program scope is acceptable to the staff.

[Preventive Actions] The LRA states that no actions are taken as part of this program to prevent aging effects or mitigate aging degradation, and the staff did not identify the need for such actions.

[Parameters Monitored or Inspected] Section B.3.10 of the LRA states that the parameters monitored or inspected for the Crane Inspection Program are the crane rails and girders for loss of material. The staff finds that these are adequate because they include the inspection of the steel rails and girders of seismically restrained cranes within the scope of license renewal.

[Detection of Aging Effects] The program detects the aging effects of loss of material through visual examination of the crane rails and girders. The staff considers visual inspection to be an effective method of detecting loss of material in crane rails and girders; therefore, the staff finds this acceptable.

[Monitoring and Trending] The program detects aging effects through visual examination of the crane rails and girders. Inspection procedures for cranes and hoists are identified in plant procedures and are in accordance with industry standards, plant experience, and other industry experience. The applicant stated that each crane and hoist is subject to several inspections. Prior to initial use, all new, reinstalled, altered, modified, extensively repaired and newly erected cranes are inspected and the results of the inspections are documented. The applicant further stated that additional inspections are conducted prior to crane operation, quarterly, and/or annually depending on the specific crane or hoist. The inspection frequencies for the cranes and hoists are based on the guidance provided by ANSI B30.2.0 and ANSI B30.16 and are considered acceptable. Plant experience supports the established frequency as being timely and effective. The applicant also indicated that no actions are taken as part of this program to trend inspection or test results.

The staff finds that these monitoring activities are adequate and the inspection frequencies based on the industry standard guidance is acceptable, and agrees that no actions are necessary for this program to trend inspection or test results.

[Acceptance Criteria] Section B.3.10 of the LRA applicant states that the acceptance criterion is no unacceptable visual indication of loss of material. The acceptance criterion is specified in the crane and hoist inspection procedures. However, it is not clear to what extent the loss of material is acceptable. Consequently, by letter dated January 28, 2002, the staff requested, in RAI B.3.10-1, a description of the criteria for (1) assessing the severity of the observed degradations; and (2) determining whether corrective action is necessary. In its response dated March 11, 2002, the applicant stated that the acceptability of crane rails and girders is based on condition monitoring. Acceptability based on condition monitoring is described in NRC Regulatory Guide 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” The criteria for visual inspection for degradation of crane rails and girders are in accordance with criteria identified in ASME/ANSI requirements and OSHA regulations. The applicant also stated that visual inspection for these types of degradation have been addressed in NRC Inspection Procedure 62002, “Inspection of Structures, Passive Components, and Civil Engineering Features at Nuclear Power Plants,” and NEI 96-03, “Industry Guideline for Monitoring Structures.” The staff finds the acceptance criteria to be acceptable.

[Operating Experience]

McGuire:
The applicant stated that the McGuire experience has found no adverse aging conditions with crane rails and girders. The significant operating experience history related to cranes dealt with functional issues.

Catawba:
The applicant stated that the Catawba experience has found no adverse aging conditions with crane rails and girders. Most issues that were identified were related to electrical equipment associated with the cranes.

The staff finds that the McGuire and Catawba operating experience indicates that the applicant's Crane Inspection Program is effective in managing the aging effects of the cranes.

FSAR Supplement: The staff reviewed the FSAR Supplement provided in UFSAR Section 18.2.7 as presented in Appendix A-1 and Appendix A-2 of the LRA for McGuire and Catawba, respectively, and compared this information to that which was provided in Section B.3.10 of the LRA and the clarifications provided by the applicant in response to RAI B.3.10-1. The staff finds that some important industry standards and the NRC guidelines used for the AMP are not incorporated into Section 18.2.7 of the FSAR Supplement. The applicant is requested to update the FSAR Supplement to incorporate those standards and guidelines. This issue is characterized as open item 3.5-5.

In conclusion, the staff reviewed the information provided in Section B.3.10 of the LRA and the summary description of the crane inspection activities in Appendix A of the LRA. In addition, the staff considered the applicant's March 11, 2002, response to the staff's RAI. On the basis of its review and the above evaluation, the staff finds that the Crane Inspection Program will adequately manage the aging effects such that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.3.3 Conclusions

The staff reviewed the information in Section 3.5.3 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the equipment and component supports will be adequately managed so that there is reasonable assurance that these supports will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.4 Aging Management Review for High-Strength Structural Bolting

Table 3.5-3 provides no information to address crack initiation and growth from SCC for high-strength, low-alloy bolts. The last item on page 3.5-18 of Table 3.5-1 of the SRP-LR addresses the issue of bolting integrity for ASME Class I piping and components supports. It indicates that no further evaluation is required if there is a bolting integrity program to address the cracking initiation and growth from SCC for high strength low-alloy bolts. By letter dated January 23, 2002, the staff requested, in RAI 3.2-1, that the applicant state whether there is such a program and provide the reference.

3.5.4.1 Aging Effects

In its response dated April 15, 2002, the applicant stated that structural bolting used in various structural components would be addressed. High strength structural bolting is included as part of the structural component, such as pipe support, equipment support, structural steel, etc., and is addressed in Section 3.5 of the LRA. According to industry literature, most degradation of structural connections results from galvanic or anodic corrosion. Loss of material is the aging effect requiring management during the period of extended operation.

Regarding stress corrosion cracking of high strength low alloy structural bolting, the applicant stated that industry experience revealed a common feature of the failures. It shows that high strength and/or overly hardened materials have been installed in humid environments and subjected to high sustained tensile stresses. Contaminants, such as those from lubricants, may also be a contributing factor. The majority of stress corrosion cracking failures in the industry involving bolting were due to fabrication issues and were identified prior to commercial operation. No McGuire or Catawba operating experience exists to suggest stress corrosion cracking is a concern for license renewal and no specific program is required.

On the basis of its review of the RAI response pertaining to high-strength structural bolting, the staff finds that all applicable aging effects were identified, and the aging effects identified are appropriate for the combination of materials and environments listed.

3.5.4.2 Aging Management Programs

Loss of material of structural components including the bolting is managed by the In-service Inspection Plan - Subsection IWF and the Inspection Program for Civil Engineering Structures and Components. Indications of potential problems would be noted through visual inspection of coating integrity and obvious signs of loss of material such as corrosion, rust, etc. Loss of material of these components is addressed through the In-service Inspection Plan - Subsection IWF or the Inspection Program for Civil Engineering Structures and Components. The In-service Inspection Plan - Subsection IWF and the Inspection Program for Civil Engineering Structures and Components are described in Appendix B, Sections B.3.20.2 and B.3.21, respectively, of the LRA. The inspection of the structural bolting for degradation would be included with the component.

The In-service Inspection Plan - Subsection IWF program and the Inspection Program for Civil Engineering Structures and considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for high-strength structural bolting. The staff’s evaluation of these AMPs is documented in Section 3.0 of this SER.

3.5.4.3 Conclusions

Based on the above discussion, the staff finds that the applicant's response clarifies and satisfactorily resolves this issue concerning the structural bolting as described in RAI 3.2-1. The staff concludes that the applicant has demonstrated that the aging effects associated with high-strength structural bolting will be adequately managed so there is reasonable assurance that these components will perform their intended functions consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6 Aging Management of Electrical and Instrumentation and Controls

The applicant described its AMR of electrical and instrumentation and controls components requiring AMR in Section 3.6 of the LRA. The AMR for all non-EQ insulated cables and connections is generically applicable to both McGuire and Catawba. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effect of aging on the electrical and instrumentation and controls components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

The applicant based its review on industry literature, plant operating experience and lessons learned from previous reviews performed for license renewal. Aging effects caused by heat and radiation, moisture and voltage stress of medium-voltage cables, and boric acid ingress into connector pins are included in the AMR of non-EQ insulated cables and connections. Details of aging effects are provided in Table 3.6-1, on page 3.6-1, of the LRA.

3.6.1 Aging Effects Caused by Heat and Radiation

3.6.1.1 Technical Information in the Application

In Section 3.6.1 of the LRA, the applicant described the process it used to identify the applicable aging effects of the electrical and instrumentation and controls components. The applicant used a bounding plant space approach to determine the required aging management program and activities that will manage aging effects caused by heat and radiation such that the intended function of non-EQ insulated cables and connections is maintained consistent with the current licensing basis for the period of extended operation.

The cable and connection material of interest for the aging management review is the primary conductor insulating material. Using the plant spaces approach, cable and connection insulation materials properties bound the aging of installed cables and connections are used in the aging management review. The 60-year service-limiting temperature and 60-year service-limiting radiation dose for the bounding insulation materials are listed in Table 3.6-2, on page 3.6-2, of the LRA.

The review of aging effects caused by heat and radiation includes the identification of the service conditions for insulated cables and connections. Service conditions include the ambient temperature with ohmic heat for power applications. The service conditions for non-EQ insulated cable and connections are listed in Table 3.6-3, page 3.6-2, of the LRA. The service conditions identified in Table 3.6-3 are bounding values. These bounding values are greater than the actual values for most plant areas due to factors such as daily and seasonal temperature fluctuations and unit outages.

In Table 3.6-4, the applicant compares the service conditions to insulation material 60-year service-limiting temperature and radiation dose for the bounding insulation materials. The results of the comparison are provided in the right hand column of Table 3.6-4 and are discussed below.

There are plant areas where the bounding service conditions are greater than the 60-year service-limiting temperature or radiation dose; and are identified with a "No" in the right hand column of Table 3.6-4, page 3.6-3, of the LRA. This signifies that some insulation materials are not suited for the bounding service conditions for 60 years of service. Based on this finding, the applicant chose not to define the service conditions for specific plant areas. Instead, the applicant will require aging management to manage the aging effects so that it can demonstrate a reasonable assurance that the intended functions of non-EQ insulated cables and connections will be maintained consistent with the current licensing basis through the period of extended operation. A new program, "The Non-EQ Insulated Cables and Connections Aging Management Program," will be implemented to demonstrate this reasonable assurance. The non-EQ insulated cables and connections within the scope of this program include non-EQ cables used in low-level signal monitoring and nuclear instrumentation.

3.6.1.1.1 Aging Effects

Table 3.6-1 of the LRA identifies the following aging effects for non-EQ insulated cables and connections caused by heat and radiation:

- Embrittlement
- Cracking
- Melting
- Discoloration
- Swelling

3.6.1.1.2 Aging Management Program

Table 3.6-5 of the LRA credits the Non-EQ Insulated Cables and Connections Aging Management Program to manage the identified aging effects for insulation materials. A description of this AMP is provided in Appendix B of the LRA. The applicant concludes that the aging effects of accessible non-EQ insulated cables and connections caused by heat or radiation will be adequately managed by this AMP such that there is reasonable assurance that accessible non-EQ insulated cables and connections will perform their intended function in accordance with the current licensing basis during the period of extended operation.

3.6.1.2 Staff Evaluation

This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management program credited for the aging management of insulated cables and connections at McGuire and Catawba nuclear stations. The staff's evaluation includes a review of the aging effects considered. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on cables will be adequately managed during period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.1.2.1 Aging Effects

In most areas within a nuclear power plant, the actual ambient environment (e.g., temperature, radiation, or moisture) are less severe than the plant design environment. However, in a limited number of localized areas, the actual environments may be more severe than plant design environment. Conductor insulation materials used in cables and connections may degrade more rapidly than expected in the adverse localized environments. An adverse localized environment is limited to certain plant area that is significantly more severe than the specific service condition for the cable. An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

Thermal-induced degradation in cable jacket and insulation materials can result in reduced elongation and decrease in tensile strength. Visible indications of thermal aging may include embrittlement, cracking, melting, discoloration, and swelling of the jacket and insulation. Radiation-induced degradation in cable jacket and insulated materials produces change in organic material properties, including reduced elongation and tensile strength. Visible indication of radiative aging may include embrittlement, cracking, discoloration, and swelling of the jacket and insulation material.

The applicant identified embrittlement, cracking, melting, discoloration, and swelling as applicable aging effects for the insulated cables and connections. The staff concurs with the aging effects identified above by the applicant for the insulated cables and connections.

3.6.1.2.2 Aging Management Programs

The applicant identified the Non-EQ Insulated Cables and Connections Aging Management Program to manage the aging effects of accessible non-EQ insulated cables and connections caused by heat or radiation. The applicant describes this program in Appendix B of the LRA, Section B.3.23, "Non-EQ Insulated Cables and Connections Aging Management Program."

<u>Non-EQ Insulated Cables and Connections Aging Management Program</u>

The staff's evaluation of the applicant's AMP focused on the program element rather than details of specific plant procedures. To determine whether the applicant aging management programs are adequate to manage the effect of aging so that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, and (7) operating experience. The staff's evaluation of the elements for corrective action, confirmation process, and administrative controls is documented in Section 3.0.4 of this SER. The staff's evaluation of the remaining seven elements follows.

[Scope] The applicant states that the scope of the Non-EQ Insulated Cables and Connections Aging Management Program includes accessible (able to be approached and reviewed easily) non-EQ (not subject to 10 CFR 50.49 Environmental Qualification requirements) insulated electrical cables and connections (power, instrumentation and control applications) installed in the reactor buildings, auxiliary building and turbine building. The Non-EQ insulated cables and connections within the scope of this program includes non-EQ cables used in low-level signal applications that are sensitive to reduction in insulation resistance such as radiation monitoring and nuclear instrumentation. The staff finds that, with the except of low level instrumentation circuits, the scope of the program is acceptable because it includes all non-EQ insulated cables, connections that are subject to potentially adverse localized environment of heat or radiation that could cause applicable aging effects in these insulated cables and connections. The staff's evaluation of this program for low level instrumentation circuits is documented later in this section (see section titled "Low Level Instrumentation Circuits").

[Preventive Actions] The applicant states that no actions are taken as part of the Non-EQ Insulated Cables and Connections Aging Management Program to prevent or mitigate aging degradation, the staff did not identify the need for such actions.

[Parameters Monitored or Inspected] The applicant states that accessible non-EQ insulated cables and connections installed in the reactor buildings, auxiliary building and turbine building are visually inspected (per the Non-EQ Insulated Cables and Connections Aging Management Program) for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. Cable and connection jacket surface anomalies are precursor indication of conductor insulation aging degradation from heat or radiation in the presence of oxygen and may indicate the existence of an adverse localized equipment environment. An adverse localized equipment environment is a condition in a limited plan area that is significantly more severe than the specified service condition for the insulated cable or connection. The staff finds the inspection approach acceptable because it provides means for monitoring the applicable aging effects for accessible in-scope non-EQ insulated cables and connections.

[Detection of Aging Effects] The applicant states in accordance to the information provided in Monitoring and Trending, the Non-EQ Insulated Cables and Connections Aging Management Program will detect aging effects for accessible non-EQ insulated cables and connections caused by heat and radiation prior to loss of intended function. The staff finds the inspection scope and inspection technique acceptable on the basis that the AMP is focused on detecting change in material properties of the insulation. Change in material property of the insulation is the applicable aging affect when cables and connections are exposed to an adverse, localized environment.

[Monitoring & Trending] The applicant states that accessible non-EQ insulated cables and connections installed in the reactor building, auxiliary building and turbine building are visually inspected per the Non-EQ Insulated Cables and Connections Aging Management Program at least once every 10 years. EPRI TR-109619, Guideline for the Management of Adverse Localized Equipment Environment, is used as guidance in performing the inspections. Trending actions are not required as part of the Non-EQ Insulation Cables and Connection Aging Management Program. The staff found the absence of a trending program acceptable since the test is performed every 10 years and, therefore, is not conducive to trending.

For McGuire, the first inspection (per the Non-EQ Insulated Cables and Connections Aging Management Program) will be completed following issuance of renewed operating licenses for McGuire 1 and by June 12, 2021 (the end of the initial license). For Catawba, the first inspection (per the Non-EQ Insulated Cables and Connections Aging Management Program) will be completed following issuance of renewed operating licenses for Catawba 1 and by December 6, 2024 (the end of the initial license). The staff finds that 10-year inspection frequency is an adequate period to preclude failures of the conductor insulation since aging degradation is a slow process. A 10-year inspection frequency will provide two data points during a 20-year period, which can be used to characterize the degradation rate. The visual technique is acceptable because it provides indication that can be visually monitored to preclude aging effects of accessible cables and connections.

[Acceptance Criteria] The acceptance criteria for inspection performed per the Non-EQ Insulated Cables and Connections Aging Management Program is no unacceptable visual indications of cable and connection jacket surface anomalies that suggest conductor insulation degradation exists, as determined by engineering evaluation. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. The staff finds the acceptance criteria acceptable because they should ensure that the cables and connections intended functions are maintained under all CLB design conditions during the period of extended operation.

[Operating Experience] The applicant states that the Non-EQ Insulated Cables and Connections Aging Management Program is a new program for which there is no operating experience. However, operating experience has shown that adverse localized environments caused by heat or radiation for electrical cables and connections may exist next to or above (within three feet of) steam generators, pressurizes or hot process pipes such as feedwater lines. The staff finds that the proposed inspection program will detect the adverse localized environment caused by heat or radiation of electrical cables and connections.

FSAR Supplement: The staff has reviewed the UFSAR supplement in Sections 18.2.19 and 18.2.18 of the LRA for McGuire (Appendix A.1) and Catawba (Appendix A.2), respectively. The staff confirmed that the information provided in the FSAR supplements addresses the applicable elements of the programs for non-EQ insulated cables and connections. However, the staff notes that the FSAR supplement does not address low level instrumentation circuits, which is discussed in the following section. Therefore, the FSAR supplements are acceptable for non-EQ cables except for those non-EQ cables in low level instrumentation circuits as discussed below.

Low Level Instrumentation Circuits

The aging management activity submitted by the applicant does not utilize the calibration approach for non-EQ electrical cables used in circuits with sensitive, low level signals. Instead, these cables are simply combined with all other non-EQ cables under the visual inspection activity. The staff believes, however, that visual inspection alone would not necessarily detect reduced insulation resistance (IR) levels in cable insulation before the intended function is lost. Exposure of electrical cables to localized environments caused by heat or radiation can result in reduced IR. Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in IR is a concern for circuits with sensitive, low-level signals such as radiation monitoring and nuclear instrumentation since it may contribute to inaccuracies in instrument loop.

The staff is not convinced that aging of these cables will initially occur on the outer casing resulting in sufficient damage that visual inspection will be effective in detecting the degradation before IR losses lead to a loss of its intended function, particularly if the cables are also subject to moisture. Therefore, by letter dated January 17, 2002, the staff requested, in RAI 3.6.1-1, the applicant to provide a technical justification that will demonstrate that visual inspection will be effective in detecting damage before current leakage can affect instrument loop accuracy.

In its response dated March 8, 2002, the applicant reiterated the view that for low-voltage cables, embrittlement and significant cracking (through cracks) of the cable jacket and conductor insulation would have to occur before the introduction of moisture around the cable could be an issue. The applicant stated that, having performed extensive, plant-wide visual inspection as part of license renewal preparatory work at Oconee, Duke has a very high confidence that the visual inspection will detect early degradation of insulation of all types of cables and connections including those that are the subject of the staff's RAI. The applicant also stated that the Sandia Report (SAND) 96-0344 provides an evaluation of aging and aging management for cables and connections. SAND 96-0344, Section 5.2.2, Measurement of Component or Circuit Properties, states that diagnostic techniques to assist in the assessment of the functionality and condition of power plant cables and termination are described as follows: "Significant changes in mechanical and physical properties (such as elongation-at-break and density) occur as a result of thermal-and radiation-induced aging. For low voltage cables, these changes precede changes to the electrical performance of the dielectric. Essentially, the mechanical properties must change to the point of embrittlement and cracking before significant electrical changes are observed..." "Embrittlement and cracking" are signs of extensive aging that are easily detectable by visual inspection. Signs of less extensive aging, such as discoloration, are also easily detectable by visual inspection. Visual inspection can detect aging degradation early in the aging process before significant aging degradation has occurred. SAND 96-0344 Section 5.2.2.1.2, Insulation Resistance (IR) - Advantage/Disadvantages, provides further information on insulation resistance as an electrical property related to aging of cables as follows:

> IR may give some indication of the aging of connections, however, it is generally considered of little use in predicting the aging of a cable. IR properties of dielectrics may change little until severe degradation of mechanical properties occurs. These measurements display some gradual changes with aging, but are generally nowhere near as sensitive to aging as techniques based on mechanical properties....Conversely, even gross insulation damage may not be evidenced by changes in IR; for example, and insulation cut-through surrounded by dry air may not significantly affect IR readings... Testing is usually conducted as a pass/fail...

Having reviewed the applicant's response, the staff undertook its own review of several aging management references. Page 3-5 of the SAND 96-0344 report (Reference 3.6-1) referenced by the applicant identified polyethylene insulated instrumentation cables located in close proximity to fluorescent lighting that had developed spontaneous circumferential cracks in exposed portions of the insulation. For some of the affected cables the cracking was severe enough to expose the underlying conductor, however, no operational failures were documented as a result of this degradation.

Section 5.2.2 of the SAND 96-0344 referred to by the applicant only assumes dry conditions where cable cracking occurs. V.N. Shah and P.E. MacDonald on page 855 of Ref. 3.6-2 state that breaks in insulation systems that are dry and clear are normally not detectable with insulation resistance tests of 1000V or less. Insulation resistance tests can detect some types of gross insulation damage, cracking or insulation, and the breach of connector seals, provided there is enough humidity or moisture to make the exposed leakage surfaces conductive.

Electric Power Research report, EPRI TR-103834-P1-2 (Ref 3.6-3) also supports the above view. It states on page 1.4-8 that normal or high insulation resistance may not indicate undamaged insulation in that a through-wall cut or gouge filled with dry air may not significantly affect the insulation resistance. The SAND 96-0344 report, on page 3-51, states that instances of low-voltage cable and wire shorting to ground induced by moisture may, in fact, be due to moisture intrusion through preexisting cracking, and effect of thermal and/or radiation exposure.

In summary, it appears from this literature and the applicant's response to the staff's RAI that visual inspection of low voltage, low signal level instrumentation circuits can be an effective means to detect age related degradation due to adverse localized environments. Because a moisture environment can apparently hasten the failure of these circuits if they have previously undergone age-related degradation, the disposition of a degraded cable should consider the potential for moisture in the area of the degradation.

By letter dated July 9, 2002, the applicant agreed to add the following statement to the Corrective Actions & Confirmation Process of the Non-EQ Insulated Cables and Connections Aging Management Program: "[The program] should consider the potential for moisture in the area of degradation." The staff finds this change to the Corrective Actions & Confirmation Process element of the Non-EQ Insulated Cables and Connections Aging Management Program acceptable since the applicant has agreed to address the potential for moisture-induced signal degradation or failure. The staff notes that the FSAR supplement should be updated to reflect this change. Pending the staff's receipt of updated information in the FSAR supplement, this is characterized as confirmatory item 3.6.1-1.

The staff noted that the above finding on low voltage instrumentation circuits is not necessarily the case for high range radiation monitor and neutron monitoring system cables. The SAND 96-0344 report referenced by the applicant states on Page 3-36 that neutron monitoring systems (including source, intermediate, and power range monitors) were separated into their own category based on (1) their substantial difference with typical low- and medium-voltage power, control, and instrumentation circuits, and (2) the relatively large number of reports related to these devices and identified in the database. The report states that neutron detectors are frequently energized at what is commonly referred to as "high" voltage, usually between 1 kV and 5 kV. This is not high voltage in the sense of power transmission voltage, but rather elevated with respect to other portions of the detecting circuit. The report included the lower voltage non-detection portion of typical neutron monitoring equipment in the low voltage equipment category, but separated out the 1kV to 5kV neutron detectors into a separate category that included neutron monitor cables and connectors.

The high voltage portion of the neutron monitoring systems would appear to be a worst case subset of the low signal level instrumentation circuit category. These circuits operate with low level logarithmic signals that are sensitive to relatively small changes in signal strength, and they operate at a high voltage which could create larger leakage currents if that voltage is impressed across associated cables and connections. Radiation monitoring cables have also been found to be particularly sensitive to thermal effects. NRC Information Notice 97-45, Supplement 1, describes this phenomenon. The neutron monitoring circuits and radiation monitors, therefore, might be candidates for the calibration approach but not necessarily the visual inspection approach.

The applicant should provide a technical justification for high range radiation monitor and neutron monitoring instrumentation cables that will demonstrate that visual inspection will be effective in detecting damage before current leakage can affect instrument loop accuracy. This issue is characterized as open item 3.6.1-1.

3.6.1.3 Conclusion

Based on the review of the LRA and the applicant's response to the staff's RAI, the staff concludes that, except for open item 3.6.1-1 pertaining to high range radiation monitor and neutron monitoring instrumentation cables, the implementation of Non-EQ Insulated Cables and Connections Aging Management Program will provide a reasonable assurance that the aging effects of heat and radiation on insulated cables and connections will be managed. This program will provide reasonable assurance that the intended functions of electrical cables and connections will be maintained consistent with the current licensing basis through the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2 Aging Effects Caused by Moisture and Voltage Stress for Inaccessible Medium-Voltage Cables

3.6.2.1 Technical Information in the Application

In Section 3.6.2 of the LRA, the applicant described the aging effects caused by moisture and voltage stress for inaccessible medium-voltage cables.

3.6.2.1.1 Aging Effects

The applicant states that it has identified aging effects caused by moisture and voltage stress as a potential aging effects for inaccessible (for example, in conduit or direct buried) non-EQ (not subject to 10 CFR 50.49 Environmental Qualification requirements) medium-voltage cables that are exposed to significant moisture while energized. Significant moisture is defined by the applicant as exposure to long-term (over a long period such as a few years), continuous (going on or extending without interruption or break) standing water. Periodic exposures to moisture that lasts for shorter periods are not significant (for example, rain and drain exposure that is normal to yard cable trenches). Medium-voltage cables routed in conduit at Catawba are not a concern due to the design criteria documented in UFSAR Section 8.3.1.4.5.1, Cable Installation, that conduit run are sloped for drainage. In addition to being exposed to long-term continuous standing water and voltage stress, inaccessible non-EQ medium-voltage cables must normally be energized more than 25 percent of the time in order to be susceptible to electrical degradation. The applicant also states that the two criteria identified above are conservative and are used only as threshold values for an inaccessible non-EQ medium-voltage cable to be identified as susceptible to aging effects caused by moisture and voltage stress. A qualifier to these two criteria is that if an inaccessible non-EQ medium-voltage cable is designed for or specified for the conditions described in these two criteria then the cable is not considered susceptible to aging effects caused by moisture and voltage stress.

3.6.2.1.2 Aging Management Programs

Table 3.6-5 of the LRA credits the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program for managing the identified aging effects for inaccessible non-EQ medium-voltage cables. A description of this AMP is provided in Appendix B of the LRA. The applicant concludes that this program will provide reasonable assurance that the intended functions of inaccessible medium-voltage cables will be maintained consistent with the CLB through the period of extended operation.

3.6.2.2 Staff Evaluation

This section the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management program credited for the aging management of inaccessible non-EQ medium voltage cables at McGuire and Catawba. The staff's evaluation includes a review of the aging effects considered. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on cables will be adequately managed during period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.2.2.1 Aging Effects

Most electrical cables in nuclear power plants are located in dry environments. However, some cables may be exposed to condensation and wetting in inaccessible locations, such as conduits, cable trenches, cable troughs, duct banks, underground vaults or direct buried installations. When an energized cable not specifically designed for submergence is exposed to these conditions, water treeing or a decrease in the dielectric strength of the conductor insulation can occur. This can potentially lead to electrical failure. The growth and propagation of water trees is somewhat unpredictable and occurrences have been noted for cable operated below 15 kV. Water treeing is a long-term degradation and failure phenomenon that is documented only for medium-voltage electrical cables.

The applicant identified formation of water trees and localized damage as applicable aging effects for the inaccessible non-EQ medium-voltage cables caused by moisture and voltage stress. The staff concurs with the aging effects identified above by the applicant for inaccessible medium-voltage cables.

3.6.2.2.2 Aging Management Program

The staff's evaluation of the applicant's AMP focused on the program element rather than details of specific plant procedures. To determine whether the applicant aging management programs are adequate to manage the effect of aging so that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 7 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, and (7) operating experience. The remaining 3 elements (corrective action, confirmation process and administrative controls) are evaluated under Section 3.0.4 of the staff's SER. Therefore, these three elements will not be discussed further in this section.

[Scope] In the previous AMP, the scope of the Inaccessible Non-EQ Medium-Voltage Cable Aging Management Program includes inaccessible (for example, in conduit or direct buried) non-EQ (not subject to 10 CFR 50.49 Environmental Qualification requirement) medium-voltage cables that are exposed to significant moisture with significant voltage. Significant moisture is defined by the applicant as exposure to long-term (over a long period such as a few years), continuous (going on or extending without interruption or break) standing water. Periodic exposures to moisture that last for short periods are not significant (i.e., normal rain and drain exposure that is normal to yard cable trenches). Significant voltage exposure is defined as being subjected to system voltage for more than 25 percent of the time. The moisture and voltage exposures described as significant in these conditions are not significant for medium-voltage cable that are designed for these conditions (e.g., continuous wetting and continuous energization is not significant for submarine cables).

It was not clear to the staff that exposure of inaccessible medium-voltage cables to moisture for a period of "a few years" is not significant. By letter dated January 17, 2002, the staff requested, in RAI B.3.19-2, the applicant to explain why exposure to moisture over more than a few days, and up to a few years, is not significant. In response to the staff request, in letter dated April 15, 2002, the applicant states that based on a review of industry literature on the topic of medium-voltage cables being exposed to moisture for long periods, no quantifiable data was found in the documents. However, the data and discussion in this industry literature (for example, EPRI TR-103834-P1-2, “Effects of Moisture on the Life of Power Plant Cables,” and SAND 96-0344, “Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Termination”) provide the general conclusion that there should not be a problem with a medium-voltage cable even if it is exposed to moisture for several years.

The staff noted that the applicant’s reference (SAND96-0344, Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cables and Termination) states in Section 4.1.2.4:

> Note, however, that even minor and/or intermittent surface condensation, in conjunction with voltage stress and contaminants, may create an environment where surface tracking may occur. Furthermore, some evidence exists to indicate that the rate of diffusion of water through a polymer is relatively independent of form [4.38]. Therefore, the water diffusion rate for a "dry" material in a 100 percent RH atmosphere may not be different than that for the same material completely submerged in water.

It was not clear to the staff that inaccessible cables exposed to moisture for a period of "a few years" was not significant. The applicant’s response did not resolve the issue of cables exposure to wet conditions for which they are not designed.

By letter dated July 9, 2002, the applicant provided the following statement to resolve this issue:

> Duke agrees with the staff on this point. To resolve this item, Duke has eliminated the qualifier "significant" when describing moisture with regards to the program. The program now takes a bounding approach by stating, "Cables that are direct[ly] buried, run in horizontally-run buried conduit or run in outside cable trenches are assumed to be exposed to standing water." In-scope medium-voltage cables that are exposed to standing water and also exposed to significant voltage will be tested.

As a result of eliminating the qualifier for "significant" when describing moisture in the programs, the applicant proposes to revise the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program attributes to the following:

Scope **–** The scope of the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* includes inaccessible non-EQ medium-voltage cables within the scope of 10 CFR 54.4 that are exposed to significant voltage and to standing water (for any period of time).

Key Definitions and Assumptions: Inaccessible cables are those that are not able to be approached and viewed easily, such as in conduits or cable trenches; all others are accessible. A cable that has a portion of the cable routing that is inaccessible is an inaccessible cable. Non-EQ means not subject to 10 CFR 50.49 Environmental Qualification requirements. Medium-voltage cables are those applied at a system voltage greater than 2kV. Significant voltage is defined as exposure to system voltage for more than twenty-five percent of the time. Cables that are direct buried, run in horizontally-run buried conduit or run in outside cable trenches are assumed to be exposed to standing water.

Preventive Actions **–** Preventive actions are not included in the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program*.

Parameters Monitored or Inspected – Medium-voltage cables within the scope of the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* are tested to provide an indication of the condition of the conductor insulation. The specific type of test performed will be determined before each test. Each test performed for a cable may be a different type of test.

Detection of Aging Effects **–** Medium-voltage cables within the scope of the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* are tested at least once every 10 years. This is an adequate frequency to preclude failures of the conductor insulation.

Monitoring & Trending **–** Trending actions are not included in the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program*.

For McGuire, the first test per the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* will be completed following issuance of renewed operating licenses for McGuire Nuclear Station and by June 12, 2021 (the end of the initial license of McGuire 1). For Catawba, the first test per the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* will be completed following issuance of renewed operating licenses for Catawba Nuclear Station and by December 6, 2024 (the end of the initial license of Catawba 1).

Acceptance Criteria **–** The acceptance criteria for each test is defined by the specific type of test performed and the specific cable tested.

Corrective Actions & Confirmation Process **–** Further investigation through the corrective action program is performed when the acceptance criteria are not met. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other medium-voltage cables within the scope of this program. Confirmatory actions, as needed, are implemented as part of the corrective action process.

Administrative Controls **–** The *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* is controlled by plant procedures.

Operating Experience **–** Operating experience is not relevant for this new program.

The staff finds that the scope of the revised program acceptable since the applicant has agreed to eliminate the qualifier of "significant" when describing cables that are exposed to moisture and this issue is resolved. The staff evaluated the applicant's revised attributes for Parameters Monitored or Inspected, Detection of Aging Effects, Acceptance Criteria, and Corrective Action and Confirmation Process in the following paragraphs. The other attributes were not affected by the revisions to this program. Therefore, the staff evaluated these attributes as they were described in the LRA. The staff notes that the FSAR supplement should be revised to reflect the change in the Inaccessible Non-EQ Medium-Voltage Cable Aging Management Program, as discussed in its evaluation of the FSAR supplement below.

[Preventive Actions] In the previous AMP, the applicant stated that no preventive actions are required as part of the Inaccessible Non-EQ Medium-Voltage Cable Aging Management Program. Periodic actions may be taken to prevent inaccessible non-EQ medium-voltage cables from being exposed to significant moisture such as inspecting for water collection in cable manholes and conduit and draining water as needed. Testing of a cable per this program is not required when such preventive actions are taken since the significant moisture criteria defined under Scope would not be met.

Periodic actions should be taken to prevent cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes and conduit and draining water as needed. Medium-voltage cables for which such actions are taken are not required to be tested. By letter dated January 17, 2002, the staff requested the applicant in RAI B.3.19-1 to explain why no preventive actions were specified as part of its AMP. In its response dated April 15, 2002, the applicant stated that the McGuire and Catawba proposed program for medium-voltage cable is written specifically for "inaccessible medium-voltage cables, i.e., cables that cannot be accessed." In a long cable run in a conduit, concrete trench or direct buried, most of the length is inaccessible, which means that most of the cable length is not accessible for inspection to determine if it is exposed to significant moisture. If any portion of a medium-voltage cable along its entire run is inaccessible and could be subject to significant moisture exposure, that cable would be identified as inaccessible and possibly subject to testing per McGuire and Catawba program. The McGuire and Catawba program for medium voltage cable was not written for accessible medium-voltage cables. During the review performed to respond to the staff's RAI, it was realized that there may be cases where it is practical to perform periodic actions to limit exposure of medium-voltage cables to moisture and, thus, mitigate any aging affects. These actions, such as inspecting cable manholes for water collection, would mainly cover the accessible portions of these cables that may provide symptomatic evidence of the conditions to which other portions of the cable are exposed. Based on the review performed to respond to the staff's RAI, the applicant would change the program descriptions contained in McGuire FSAR Supplement 18.2.15 and Catawba FSAR Supplement 18.2.14 by replacing existing text with the following text in the Scope, Preventive Actions and Monitoring & Trending program attributes:

> [Scope] The scope of the Inaccessible Non-EQ Medium-Voltage Cable Aging Management Program includes inaccessible non-EQ medium-voltage cables within the scope of 10 CFR 54.4 that are exposed to significant voltage simultaneously with significant moisture.
>
> Key Definition and Assumptions: Inaccessible cables are those that not able to be approached and viewed easily, such as in conduits or cable trenches; all other are accessible. Non-EQ means not subject to 10 CFR 50.49 Environmental Qualification requirements. Medium-voltage cables are those applied at a system voltage greater than

2kV and less than 15kV. Significant voltage is defined as exposure to system voltage for more than 25 percent of the time. Significant moisture is defined as exposure to long term (over a long period such as few years), continuous (going on or extending without interruption or break) standing water. Periodic exposures to moisture for shorter periods are not significant (for example, rain and drain exposure that is normal to yard cable trenches). Significant moisture is assumed to be present unless engineering data indicates otherwise. The moisture and voltage exposures described as significant in these definition are not significant for medium-voltage cables that are designed for these conditions (for example, continuous wetting and continuous energization is not significant for submarine cables).

[Preventive Actions] Periodic action are taken where practical, as determined by the accountable engineer, to mitigate any aging effects by limiting the exposure of inaccessible non-EQ medium-voltage cables to moisture, such as inspecting for water collection in cable manholes and conduits and draining water as needed.

[Monitoring & Trending] Inaccessible non-EQ medium-voltage cables exposed to significant moisture and significant voltage are tested at least once every 10 years per the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program to provide an indication of the condition of the conductor insulation and the ability of the cable to perform its intended function. The specific type of test performed will be determined before each test. Each test performed for a cable may be a different type of test. Testing of a cable per this program is not required if periodic actions as described under preventive actions are taken and those actions prevent, with reasonable assurance, the cable from being exposed to significant moisture (since the significant moisture criteria defined under Scope would not be met).

The staff found the applicant’s response acceptable because the applicant would take preventive actions, when practical, to mitigate any aging effects by limiting the exposure of inaccessible cables to moisture. Testing of a cable per this program is not required if periodic actions are taken and those actions prevent the cable from being exposed to significant moisture.

In July 9, 2002, letter, the applicant revised the preventive action attribute to the following:

Preventive actions are not included in the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program. The staff finds it acceptable since the applicant chooses to test the medium-voltage cables that are exposed to significant voltage and standing water for any period of time every 10 years, no prevent actions are necessary.

[Parameters Monitored or Inspected] Medium-voltage cables within the scope of the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program are tested to provide an indication of the condition of the conductor insulation. The specific type of test performed will be determined before each test. Each test performed for a cable may be a different type of test. The staff finds the approach acceptable because the in-scope, medium-voltage cables exposed to significant moisture and significant voltage are tested to provide an indication of the condition of the conductor insulation.

[Detection of Aging Effects] Medium-voltage cables within the scope of the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* are tested at least once every 10 years. This is an adequate frequency to preclude failures of the conductor insulation. The staff believes, based on current knowledge that aging degradation of this cabling would be due to slow acting mechanisms, Therefore, the applicant proposed test schedule is acceptable.

[Monitoring & Trending] In the previous AMP, the applicant stated that Inaccessible non-EQ medium-voltage cables exposed to significant moisture and significant voltage are tested at least once every 10 years per the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program to provide an indication of the condition of the conductor insulation and the ability of the cable to perform its intended function. The specific type of test performed will be determined before each test. Each test performed for a cable may be a different type of test. Testing of a cable per this program is not required if periodic actions are taken and if those actions prevent, with reasonable assurance, the cable from being exposed to significant moisture (since the significant moisture criteria defined under Scope would not be met). Sine the alternate visual inspection program was proposed to testing, the staff determined that the applicant's monitoring and trending attribute did not provide adequate information about the proposed alternative inspection program to testing in that it did not specify the following: (1) the frequency of inspection; (2) how inspection results will be monitored and trended; (3) if or when operability evaluations for degraded conditions (presence of moisture) would be performed; (4) if or when testing would be performed if moisture is identified; and (5) what corrective actions would be taken in the event that cables exposed to moisture are identified. By letter dated June 26, 2002, the staff identified potential open item B.3.19.2-1 as mentioned above and requested the applicant to provide additional information in response to this potential open item.

By letter dated July 9, 2002, the applicant stated the following:

> The alternative visual inspective program was proposed in the McGuire and Catawba LRA in an attempt to provide a distinction between cables that are exposed to moisture (rain and drain) and those that are exposed to "significant" moisture so that the cables exposed only to "rain and drain" would not require testing. Trying to quantify this distinction has proven difficult and has raised staff concerns that this distinction, improperly applied, could inadvertently exclude some applicable cables from the program. Duke acknowledges the staff's concern in this area along with the recognition that some cable installations make it impossible (by currently known means) to verify with reasonable assurance that all portions of some cable runs are not continuously exposed to moisture. Considering these factors, Duke has now eliminated this distinction regarding moisture exposure by taking a bounding approach. The aging management program will include any significant voltage exposed in-scope medium-voltage cables that are exposed to standing water (for any period of time). With the moisture distinction eliminated and all such cables included without further qualification, the need for the proposed alternative inspection program is eliminated.

Since the applicant eliminated the inspection alternative to the 10-year test described in the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program, this issue is resolved.

The applicant also revised the monitoring & trending attribute, stating that trending actions are not included in the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program. For McGuire, the first test per the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program will be completed following issuance of renewed operating licenses for McGuire and by June 12, 2021 (the end of the initial license of McGuire 1). For Catawba, the first test per the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program will be completed following issuance of renewed operating licenses for Catawba and by December 6, 2024 (the end of the initial license of Catawba 1). The staff finds that the absence of trending for testing is acceptable since the test is performed every 10 years and the staff did not see a need for such activities. The staff also finds the testing schedule acceptable to preclude failures of the conductor insulation since aging degradation is a slow process.

[Acceptance Criteria] The acceptance criteria for each test is defined by the specific type of test performed and the specific cable tested. The staff finds the above acceptance criteria acceptable on the basis that they will follow current industry standards which, when implemented, will ensure that the license renewal intended functions of the cables will be maintained consistent with the current licensing basis.

[Operating Experience] Operating experience is not relevant for this new program. Industry experience supports both the need for the program and the attributes of the applicant's program. Thus, the staff finds that operating experience is satisfactorily incorporated into the development of this new program.

FSAR Supplement: In response to the staff RAIs, the applicant proposed to revise the Inaccessible Non-EQ Medium Voltage Cables AMP. Pending the staff's receipt of the revised FSAR supplement, this is characterized as confirmatory item 3.6.2-1.

3.6.2.3 Conclusion

On the basis of the staff's evaluation described above, the staff finds that there is reasonable assurance that the effects of aging on inaccessible non-EQ medium voltage cables will be adequately managed so that the intended functions will be maintained consistent with the applicant's CLB for the period of extended operation in accordance with the requirement of 10 CFR 54.21(a)(3).

3.6.3 Aging Effects Caused by Boric Acid Ingress into Connector Pins

3.6.3.1 Technical Information in the Application

In Section 3.6.3 of the LRA, the applicant described the aging effects caused by boric acid ingress into connector pins. The applicant states that potential acid ingress into connector pins was identified as causing aging effects that needs to be managed.

3.6.3.1.1 Aging Effects

Table 3.6-1 on page 3.6-1 of the LRA identified corrosion of connector pins as an aging effect caused by exposure to borated water.

3.6.3.1.2 Aging Management Program

The applicant states that it will take credit for an existing program, the Fluid Leak Management Program (which includes boric acid leakage surveillance) for managing

aging effects caused by boric acid ingress into non-EQ connector pins at McGuire and Catawba. This AMP is described by the applicant in Section B.3.15 of the LRA.

3.6.3.2 Staff Evaluation

This section the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management program credited for the aging management of connector pins at McGuire and Catawba nuclear stations. The staff's evaluation includes a review of the aging effects considered. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on connector pins will be adequately managed during period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.3.2.1 Aging Effects

Aging effects caused by oxidation or corrosion of connector pins because of potential boric acid ingress into connector pins could cause connector failure and interfere with the operation of these circuits. The applicant identified corrosion as applicable aging effects for the connector pins. The staff concurs with the aging effects identified above by the applicant.

3.6.3.2.2 Aging Management Programs

The staff evaluated the information on aging effects caused by boric acid ingress into connector pins as presented in Section 3.6.3 of the LRA to determine if there is a reasonable assurance that the applicant has demonstrated that the aging effects for low voltage connectors will be adequately managed, consistent with the applicant's CLB for the period of extended operation.

The applicant credits the Fluid Leak Management Program to manage the aging effects caused by boric acid ingress into non-EQ low voltage connector pins. Since the Fluid Leak Management Program is credited for managing the aging of several structures and components in different systems, it is considered a common AMP and the staff's evaluation of it is documented in Section 3.0 of the SER. The AMP's effectiveness has been evaluated for electrical components as well. The staff finds that this program is adequate to manage the effect of corrosion of the electrical components.

3.6.3.3 Conclusion

Based on the review of the LRA, the staff concludes that the implementation of the Fluid Leak Management Program will provide a reasonable assurance that the aging effects of oxidation or corrosion of connector pins will be managed. This program will provide reasonable assurance that the intended functions of low voltage connectors will be maintained consistent with the current licensing basis through the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.4 References

3.6-1 Sandia Contractor Report SAND96-0344, Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations, Prepared by Ogden Environmental and Energy Services, Inc., printed September 1996

3.6-2 Aging and Life Extension of Major Light Water Reactor Components, edited by V.N. Shah and P.E. MacDonald, 1993, Elsevier Science Publishers

3.6-3 Electric Power Research Institute report, EPRI TR-103834-P1-2, Effects of Moisture on the Life of Power Plant Cables, Part 1: Medium-Voltage Cables, Part 2: Low-Voltage Cables, prepared by Ogden Environmental and Energy Services Company, Final Report, August 1994