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 SSF, of which a portion is the 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. 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 LRA as being within the scope of license renewal, and subject to an AMR. LRA 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 for 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 SSCs to the environments listed in Section 2.3.3.25 and Table 3.3-33, page 3.3-209, of the LRA 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 identified.

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 gasses from radioactive contaminated fluids and contains these gasses in holdup tanks indefinitely. Storage and subsequent decay of these gasses eliminates the need for regularly scheduled discharge of these radioactive gasses from the system into the atmosphere during normal plant operation. 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 gasses from radioactive fluids, and contains these gasses 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. 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 LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-47, pages 3.3-258 to 3.3-263, 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 of 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 for 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 effects 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 3.3-263. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for 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 LRA Section 2.3.3.38 and Tables 3.3-47, pages 3.3-258 to 3.3-263. 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 LRA 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 gasses (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 gasses or to 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 CVCS. 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 LRA 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 makeup have a "PB," or pressure boundary component function. Typically, orifices also provide the function listed as "TH" (i.e., 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 to correct the component functions for orifices listed in LRA 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 10 CFR 54.4(a)(1) of the Rule. The components associated with the compressor are only required to maintain pressure boundary integrity in support of 10 CFR 54.4(a)(1)(iii). Therefore, throttling is not a license renewal intended function of the seal and makeup 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	None Identified	None Required
			Sheltered	None Identified	None Required
Waste Gas Separators	PB	SS	Treated Water (unmonitored)	Cracking	Waste Gas System Inspection
				Loss of Material	Waste Gas System Inspection
			Sheltered	None Identified	None Required

The aging effects that result from contact of the waste gas SSCs to the environments described in the applicant's response to RAI 2.3.3.38-1, and in LRA Section 2.3.3.38 and Table 3.3-47, pages 3.3-258 through 3.3-263, 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 identified.

3.3.38.2.2 Aging Management Programs

LRA Section 2.3.3.38 and Table 3.3-47, pages 3.3-258 to 3.3-263, state 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 LRA Section 2.3.3.38 and Tables 3.3-47, pages 3.3-258 to 3.3-263, 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 of the LRA. 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.

Waste Gas System Inspection

The applicant described its Waste Gas System Inspection in Section B.3.36 of LRA Appendix B. The applicant credits this program with managing the potential aging of waste gas system structures and components that are within the scope of license renewal. The inspection activity is a one-time volumetric or visual inspection to monitor for loss of material and cracking. The staff reviewed Section B.3.36 of LRA Appendix B to determine if the applicant had demonstrated that the waste gas 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.3.36 of LRA Appendix B, the applicant stated 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 treated water and gas environments. The applicant described unmonitored treated water as condensation of water vapor in the waste gas stream, and effluent from the recombiners and separators. The applicant described the gas environment as a combination of nitrogen, hydrogen, oxygen, and fission product gasses. The applicant stated that there is uncertainty as to whether exposure to these environments could cause cracking and/or loss of material for the waste gas system components, such that they would lose their pressure boundary intended function.

The waste gas system inspection activities use a combination of volumetric and/or visual examination of selected carbon steel, stainless steel, and brass components in the system. This is a one-time inspection activity. The applicant stated that, should industry experience, or evaluation of the inspection findings, indicate 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.

[Program Scope] Section B.3.36 of LRA Appendix B states that the scope of the waste gas system inspection activities includes the carbon steel, stainless steel, and brass materials that are exposed to unmonitored treated water environments, and carbon steel materials that are exposed to gas environments that are within the license renewal boundaries for the waste gas systems at Catawba and McGuire. The scope covers the components that rely on the waste gas system inspection activities for aging management; therefore, this is acceptable to the staff.

[Preventive or Mitigative Actions] There are no preventive or mitigative 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.3.36 of LRA Appendix B 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 waste gas system are acceptable to the staff.

[Detection of Aging Effects] Section B.3.36 of LRA Appendix B states that volumetric and/or visual inspection will detect loss of material and cracking of the components. Visual exams will be used in lieu of volumetric exams if access to the internal surfaces becomes available. The use of volumetric and/or visual inspection is considered by the staff to be a reasonable means of detecting these aging effects, and is consistent with NRC and industry guidance. Therefore, the staff finds this acceptable.

[Monitoring and Trending] Section B.3.36 of LRA Appendix B states that the one-time inspections will be performed as follows:

> (1) For the brass seal water control valves on the waste gas compressors at Catawba exposed to unmonitored treated water, an inspection will be performed on one of the two seal water control valves. The results of this inspection will be applied to the other brass seal water control valve.
>
> (2) For carbon steel components exposed to unmonitored treated water environments at each site, inspections will be performed on the lower portions of decay tanks and associated drain lines where condensate is likely to accumulate. One of eight possible locations at each site will be examined. The results of this inspection will be applied to the remainder of the waste gas system carbon steel components within the scope of license renewal exposed to unmonitored treated water environment.
>
> (3) For stainless steel components exposed to unmonitored treated water environments at each site, inspections will be performed on the seal water path of the waste gas compressor. One of two possible locations at each site will be examined. The results of this inspection will be applied to the remainder of the waste gas system stainless steel components within the scope of license renewal exposed to unmonitored treated water environment.
>
> (4) For the carbon steel components exposed to a gas environment at each site, an inspection will be performed on components located between the volume control tanks and the waste gas compressor phase separators. This section of the waste gas system contains a warm, moist gas that could result in condensation on the cooler internal surfaces of the carbon steel components. As a result, corrosion of the carbon steel surfaces is more likely due to the presence of moisture and would serve as a leading indicator for the remainder of the carbon steel components. The results of this inspection will be applied to the remainder of the waste gas system carbon steel components within the scope of license renewal exposed to gas environments.

The applicant stated that if no parameters are known that would distinguish the most susceptible locations for the above inspections, then the inspection locations will be based on accessibility and radiological concerns. By letter dated January 28, 2002, the staff requested, in RAI B.3.36-1, additional information about the criteria used to distinguish the most susceptible locations. In its response dated March 15, 2002, the applicant stated that the criteria could include component geometry, operating temperatures, system operation, and previous operating experience. These are appropriate criteria for determining the most susceptible locations; therefore, the staff finds the applicant's monitoring of aging effects to be acceptable.

Section B.3.36 of LRA Appendix B states that no actions are taken as part of the program to trend the inspection results, since this is a one-time inspection. If evaluation of the inspection findings indicates that continuation of the aging effects will cause a loss of intended function(s), additional inspections will be performed and/or corrective actions 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.3.36 of LRA Appendix B 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. The LRA also states that the engineering evaluation will determine whether continued aging could cause a loss of system intended function, or whether additional inspection is warranted, and that appropriate corrective action will be taken. Because it will maintain the system intended function, the staff finds the acceptance criterion to be reasonable and acceptable.

[Operating Experience] Section B.3.36 of LRA Appendix B states that the waste gas 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 18.2.28 of the UFSAR supplement for McGuire, and Section 18.2.27 of the UFSAR for Catawba. The staff finds that the summary description is consistent with the LRA and is, therefore, 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 LRA Appendix B, 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 Waste Gas 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 be maintained 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 LRA Section 2.3.3.38 and Table 3.3-47. 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 cracking 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 (SSCs) 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 3.3-1, 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. LRA 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 (ADAMS Accession No. ML021440217), 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 (ADAMS Accession No. 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 an 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 of the LRA 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

In its response to RAI 3.2-1 dated April 15, 2002, 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, therefore, 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 made from the same material and exposed to the same environment. Programs for the system (i.e., Chemistry Control Program 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
- 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 identified.

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 LRA Appendix B, Section B.3.15, 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 LRA Appendix B, Section B.3.21, for McGuire and Catawba.

The Fluid Leak Management Program and the Inspection Program for Civil Engineering Structures are 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. Section 3.4 of the LRA defined the external and internal environments applicable to the SPCS as follows—

- 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.
- Oil and Fuel Oil — Lubricating oil is an organic fluid used to reduce friction between moving parts. Fuel oil is the fuel used for the emergency diesel generators.

The staff has reviewed Sections 2.3.4 and 3.4 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 LRA Section 2.3.4.1, "Auxiliary Feedwater System." 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 back up 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 SSCs 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 treated water and lubricating oil environments.

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 SSCs that require management:

- loss of material, cracking, and fouling of stainless steel components in 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 the identified aging effects will be effectively managed for the period of extended operation, is provided in 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 for 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 SSCs 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 identified.

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 was characterized as SER open item 3.4.1.2.2-1.

In its response dated October 28, 2002, the applicant stated that it had searched the operating experience database to determine if there had been any component failures, relevant industry operating experience, or problems discovered during routine maintenance and testing. The applicant did not find any loss of the component intended functions of the auxiliary feedwater system components that could be attributed to the inadequacy of the chemistry control program. The applicant stated that routine maintenance of other secondary system components, such as the steam generators and main turbine, provide additional operating experience because they do operate during start up and shutdown and are of the same chemistry as the feedwater system and other secondary side systems. These secondary systems have also shown no degradation affected by water chemistry.

During a meeting on September 18, 2002 (summarized by memorandum dated November 18, 2002), the staff indicated that the routine inspections of the secondary systems would not be sufficient as an alternative to the one-time inspection, without proper documentation. The staff would find the routine inspections acceptable if the applicant would commit to document inspection results of the auxiliary feedwater system and main feedwater system to demonstrate that there are no aging effects occurring, and that the chemistry control program is effective. The staff also stated that the inspection results should be available for the future NRC inspection. In its October 28, 2002, response to the open item, the applicant augmented Section 18.3 of the McGuire FSAR supplement with the following:

> Visual inspections of the interior surfaces of auxiliary feedwater system and main feedwater system components and piping will be performed when available. The inspection results will be

documented in writing and available for inspection following issuance of renewed operating licenses for McGuire Nuclear Station and by June 12, 2021 (the end of the initial license of McGuire Unit 1).

The applicant augmented Section 18.3 of the Catawba FSAR supplement with the following:

> Visual inspections of the interior surfaces of auxiliary feedwater system and main feedwater system components and piping will be performed when available. The inspection results will be documented in writing and available for inspection following issuance of renewed operating licenses for Catawba Nuclear Station and by December 6, 2024 (the end of the initial license of Catawba Unit 1).

The staff finds the applicant's augmented Catawba and McGuire FSAR supplements acceptable because the applicant will inspect these internal surfaces specifically for aging effects (loss of material) and will document its findings in the inspection procedure. This deliberate inspection will provide an opportunity to verify that the Chemistry Control Program is effective, and thereby satisfies the intent of the one-time inspection. However, the staff notes that, should the applicant identify loss of material or other aging effects it currently believes are being effectively managed by the Chemistry Control Program, then corrective actions may be required in accordance with 10 CFR Part 50, Appendix B, to repair the degraded condition. Additionally, corrective action will be necessary to prevent further age-related degradation from occurring. This may involve identification of an additional AMP or modification to the Chemistry Control Program. The staff concludes that open item 3.4.1.2.2-1 is closed.

Based on its review of LRA Table 3.4-1, and with the resolution 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 be maintained 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 Conclusions

The staff reviewed the information in LRA Table 3.4-1, "Auxiliary Feedwater System." On the basis of its review, and with the resolution 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 LRA Section 2.3.4.2, "Auxiliary Steam System." 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 clean up, start up, normal operation, and shutdown. The auxiliary steam system is a non-safety-related system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. The mechanical components subject to an 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 SSCs 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 SSCs 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
- loss of material from carbon steel in yard (trench) (Catawba only)

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
- 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 the identified aging effects will be effectively managed for the period of extended operation, is provided in 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 for 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 SSCs 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 identified.

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
- 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 be maintained 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 Conclusions

The staff reviewed the information in LRA 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 LRA Section 2.3.4.3, "Condensate System." 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-related system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. The mechanical components for the 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 SSCs 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 and treated water environments was identified as the only aging effect associated with the condensate SSCs 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 the identified aging effects will be effectively managed for the period of extended operation, is provided in 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 for 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 of loss of material that results from contact of the condensate SSCs 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 effect listed is appropriate for the combination of materials and environments identified.

3.4.3.2.2 Aging Management Programs

Table 3.4-3 of the LRA states that the following AMPs are credited for managing 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 be maintained 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 Conclusions

The staff reviewed the information in LRA 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 LRA Section 2.3.4.4, "Condensate Storage System." 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 clean up, start up, normal operation, and shutdown. The condensate storage system is a non-safety-related system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. The mechanical components for the 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 SSCs 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 a sheltered environment, which is discussed in Section 3.4.1 of the LRA.

Loss of material for carbon steel components in sheltered and treated water environments was identified as the only aging effect associated with the condensate storage SSCs 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 the identified aging effects will be effectively managed for the period of extended operation, is provided in 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 for 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 SSCs 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 identified.

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 be maintained 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 Conclusions

The staff reviewed the information in LRA 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 LRA Section 2.3.4.5, "Feedwater System." The applicant described the results of its AMR of the feedwater system for license renewal in Table 3.4-5 of the LRA.

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 an 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 materials of construction for the feedwater SSCs 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 SSCs 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 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 the identified aging effects will be effectively managed for the period of extended operation, is provided in 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 low-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 carbon steel components exposed to an internal environment of treated water, the applicant identified the Chemistry Control Program and the Flow-Accelerated Corrosion Program.

To manage the aging effects for the carbon steel and low-alloy steel components exposed to an external environment of borated water leaks in the reactor building, the applicant identified the Fluid Leak Management Program and Inspection Program for Civil Engineering Structures and Components.

To manage the aging effects for the carbon steel and low-alloy steel components exposed to the external environments of sheltered and yard, the applicant identified the Inspection Program for Civil Engineering Structures and Components.

3.4.5.2 Staff Evaluation

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging for the feedwater system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.5.2.1 Aging Effects

The aging effects that result from contact of the feedwater SSCs 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 identified.

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 AMPs. 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 be maintained 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 Conclusions

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 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 LRA Section 2.3.4.6, "Feedwater Pump Turbine Exhaust System." The applicant described the results of its AMR of the feedwater pump turbine exhaust system for license renewal in LRA Table 3.4-6.

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. Catawba UFSAR Section 10.3, "Main Steam System," provides additional information concerning the design and operation of these systems. The mechanical components subject to an 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 SSCs 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 an 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 SSCs, 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 a sheltered environment.

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 the identified aging effects will be effectively managed for the period of extended operation, is provided in 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 for the feedwater pump turbine exhaust system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.6.2.1 Aging Effects

The aging effects that result from contact of the feedwater pump turbine exhaust SSCs 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 identified.

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 AMPs. 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 be maintained 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 Conclusions

The staff reviewed the information in LRA 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 LRA Section 2.3.4.8, "Main Steam System," 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 an AMR, their intended functions, and materials of construction for the main steam system are listed in Table 3.4-7 of the LRA.

3.4.7.1.1 Aging Effects

The materials of construction for the main steam SSCs 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 an AMR are exposed to reactor building, sheltered, and yard 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 SSCs 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 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 AMPs 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 the identified aging effects will be effectively managed for the period of extended operation, is provided in 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 for 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 SSCs 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 identified.

3.4.7.2.2 Aging Management Programs

Table 3.4-7 of the LRA states that the following AMPs 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 AMPs. 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 be maintained 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 Conclusions

The staff reviewed the information in LRA 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 LRA Section 2.3.4.9, "Main Steam Supply to Auxiliary Equipment System." 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. 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 an 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 SSCs 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 an AMR are exposed to the sheltered 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 SSCs 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 supply to auxiliary equipment system.

3.4.8.1.2 Aging Management Programs

The applicant identified the following AMPs 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 AMPs, along with the applicant's discussion of how the identified aging effects will be effectively managed for the period of extended operation, is provided in 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 for 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 SSCs 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 identified.

3.4.8.2.2 Aging Management Programs

Table 3.4-8 of the LRA states that the following AMPs 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 AMPs. 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 be maintained 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 Conclusions

The staff reviewed the information in LRA 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 LRA Section 2.3.4.10, "Main Steam Vent to Atmosphere System." 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. Catawba and McGuire UFSAR Section 10.3, "Main Steam Supply System," provides additional information concerning the main steam vent to atmosphere equipment. The mechanical components subject to an AMR review, their intended functions, and materials of construction for the main steam vent to atmosphere system are listed in LRA Table 3.4-9.

3.4.9.1.1 Aging Effects

The materials of construction for the main steam vent to atmosphere SSCs 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 an AMR are exposed to sheltered and yard 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 SSCs 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, sheltered, and yard 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 AMPs 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 AMPs, along with the applicant's discussion of how the identified aging effects will be effectively managed for the period of extended operation, is provided in 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 for 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 SSCs 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 identified.

3.4.9.2.2 Aging Management Programs

Table 3.4-9 of the LRA states that the following AMPs 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 AMPs. 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 be maintained 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 Conclusions

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 LRA Sections 3.2, 3.3, and 3.4 that list closure bolting as components subject to an 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 AMR.

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 made from the same material and exposed to the same environment. Programs for the system (i.e., Chemistry Control Program 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, the applicant 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
- 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 identified.

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 LRA Appendix B, Section B.3.15.

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 LRA Appendix B, Section B.3.21.

The Fluid Leak Management Program and the Inspection Program for Civil Engineering Structures are 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).

3.5 Aging Management of Containments, Structures, and Component Supports

In LRA Section 2.1, "Scoping and Screening Methodology," 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 structures in LRA Section 2.4, "Scoping and Screening Results: Structures." The staff's evaluation of the scoping methodology and the structures included within the scope of license renewal, and subject to an AMR, is documented in Sections 2.1 and 2.4 of this SER, respectively.

Section 3.5 of the LRA defined the external and internal environments applicable to the containments, structures and component supports as follows—

- Below-grade — Below-grade portions of structures are exposed to back fill and groundwater. The groundwater at McGuire and Catawba is not aggressive. The McGuire groundwater pH ranges between 8.1 and 8.4; the chloride concentration is less than 20 ppm; and the sulfate concentration is less than 30 ppm. The Catawba groundwater pH ranges between 5.7 and 7.0; the chloride concentration is less than 25 ppm; and the sulfate concentration is less than 35 ppm.
- Borated Water — Borated water is demineralized water treated with boric acid.
- Concrete — Steel components located in concrete are protected by the alkaline environment of the concrete.
- External — External surfaces of structures are exposed to the external ambient environment.
- Ice Condenser Environment — The normal operating atmosphere in the ice condenser is at 10°F to 20°F and the absolute humidity is very low.
- Raw Water — Raw water is water from a lake, pond, or river that has been rough-filtered and possibly treated with a biocide.
- 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.
- 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.

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 TS have been identified. A discussion of the AMR results for each structure and structural component follows.

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) AMPs 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. LRA 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 is 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 is 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.

In a letter dated November 14, 2002, the applicant submitted its response to SER open item 2.3-3 pertaining to the applicant's treatment of structural sealants (subcomponents of structural members) in certain ventilation system applications for which pressure boundary integrity was an intended function (e.g., the annulus). The applicant identified cracking and shrinkage of structural sealant due to exposure to ambient conditions as potential aging effects. The applicant also provided the Ventilation Area Pressure Boundary Sealants Inspection, which it credited to monitor these aging effects.

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

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified cracking and shrinkage of structural sealant due to exposure to ambient conditions.

3.5.1.1.2 Aging Management Programs

Table 3.5-1 of the LRA credits the following AMPs with managing the identified aging effects for the components that constitute the reactor building:

- Cntainment Leak Rate Testing Program
- Containment ISI Plan — IWE
- Ice Condenser Inspections
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- Divider Barrier Seal Inspection and Testing Program
- Technical Specification SR 3.6.16.3 Visual Inspection

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified the Ventilation Area Pressure Boundary Sealants Inspection to manage the effects of cracking and shrinkage of structural sealant due to exposure to ambient conditions.

A description of these AMPs 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 AMPs during the period of extended operation.

3.5.1.2 Staff Evaluation

In addition to LRA Section 3.5, the staff reviewed the pertinent information provided in LRA Section 2.4, "Scoping and Screening Results: Structures," and the applicable aging management program descriptions provided in LRA Appendix B 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 AMPs 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 AMPs that are credited for managing the identified aging effects for the reactor building structural members.

3.5.1.2.1 Aging Effects

Table 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 the following 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.

<u>Concrete</u>: 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 LRA 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 of 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 [sic] 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 when 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 completed 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 in 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 necessary only 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 the 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 (ADAMS Accession No. 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 AMPs.

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 disputed the applicant's claim, in response to RAI 3.5-7, that AMPs 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 was characterized as SER open item 3.5-1.

On September 18, 2002, the staff met with the applicant to discuss this and other SER open items. The meeting is summarized by memorandum dated November 18, 2002. In a letter dated October 2, 2002, the applicant agreed to resolve open item 3.5-1 by committing to manage the aging of accessible concrete structural components during the period of extended operation. In electronic correspondence dated October 10, 2002 (ADAMS Accession No. ML023290464), the staff indicated that a more detailed response to the SER open item would be needed to resolve this open item and submitted the following request to the applicant:

> Please submit revised AMR results tables for all of Section 3.5, which should also include and clearly reference the concrete structures/components in the SBO recovery path that were brought into scope and for which no aging effects were identified. The revised tables must indicate the aging effect(s) for each structure or component as well as the AMP(s) credited.

To show the specific concrete components that will be managed, the applicant subsequently submitted revised AMR results tables for Section 3.5 of its LRA; these revised tables were submitted by letter dated October 28, 2002. In this letter, the applicant referenced Note 4 in the column for aging effects for each accessible concrete item in Tables 3.5-1 and 3.5-2. However, Note 4 did not specify the aging effects that would be managed during the period of extended operation. In a letter dated November 14, 2002, the applicant provided a revised Note 4, in which it committed to manage loss of material, cracking, and change in material properties for the accessible concrete components identified in Tables 3.5-1 and 3.5-2 of the LRA. Note 4, as revised by the applicant, states:

> Duke did not identify any aging effects that would result in loss of component intended function. The staff in its SER dated August 14, 2002 identified loss of material, cracking, and change in material properties to be both plausible and applicable aging effects for all concrete components. Notwithstanding the disagreement on the aging effects that require management for the period of extended operation, Duke committed, in its response to Open Items 3.5-1 and 3.5-3 provided in a letter dated October 2, 2002, to perform periodic inspections of these concrete components to manage the aging effects of loss material, cracking, and change in material properties using the *Inspection Program for Civil Engineering Structures and Components.*

The applicant's commitment to periodically inspect accessible concrete structures and components through its Inspection Program for Civil Engineering Structures and Components is acceptable to the staff. Therefore, open item 3.5-1 is closed.

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 tests 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, 50-413/02-05, and 50-414/02-05), 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 did 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 did 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. Therefore, the applicant's response to RAI 3.5-1 was initially considered by the staff to be inadequate, and this issue was characterized as SER open item 3.5-2.

In its July 9, 2002, response to the staff's potential open items letter, the applicant responded to this issue, which was characterized as RAI 3.5-1 (open item). The applicant stated that it did not commit to initiate a corrective action in the event of a potential change to the site environment, resulting from a chemical release during the period of extended operation, because such an event was not postulated. The applicant stated:

> It is simply not credible to postulate that some environmental event will occur in the future that would affect the quality of groundwater in the vicinity of Catawba or McGuire. Change in the environment due to a chemical release would be an abnormal event.

As stated in NUREG-1800, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," aging effects from abnormal events need not be postulated specifically for license renewal. After the SER was issued with this identified as open item 3.5-2, the staff reviewed the guidance provided in NUREG-1800 and reconsidered the applicant's assertion that a potential change to the site environment resulting from a chemical release during the period of extended operation would be an abnormal event. The staff agreed that such a chemical release would not need to be postulated for the purposes of performing an aging management review for license renewal. Therefore, the staff closed open item 3.5-2 without any further information from the applicant. The applicant was notified of this resolution by electronic correspondence dated September 3, 2002 (ADAMS Accession No. ML023300155).

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. Based on the reasoning stated above in RAI 3.5-7 concerning the aging management for accessible concrete components, the staff considered 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. The staff believed that, in the event of an ice condenser wall panel defrosting, the wear slab would be accessible for inspection and should be inspected for signs of degradation; however, the staff subsequently realized that it had misinterpreted the applicant's response to RAI 3.5-6 and, after the SER with open items was issued, acknowledged that the wear slab would be inaccessible even if the wall panel had defrosted. Nonetheless, the staff considered the applicant's response to RAI 3.5-6, with respect to the crane wall and the structural concrete floor, to be inadequate. This issue was characterized as open item 3.5-3.

In its response to open item 3.5-3, dated October 2, 2002, the applicant stated the following:

> The Duke response to Open Item 3.5-3 is provided in two parts: the first part concerns the ice condenser wear slab and the second part concerns the ice condenser crane wall and accessible portions of the ice condenser structural floor.

With respect to the ice condenser wear slab, Duke has performed an additional review of the design of McGuire and Catawba and determined that the ice condense wear slab is not within the scope of license renewal because it does not perform a license renewal function. The ice condenser slab is described in each station's UFSAR (Section 6.2.2 for McGuire and Section 6.7.1 for Catawba) as follows:

> The wear slab is a concrete structure whose function is to provide a cooled surface as well as to provide personnel access support for maintenance and/or inspection. The wear slab also serves to contain the floor cooling piping.

Therefore, no further aging management review of the ice condenser wear slab is required for license renewal.

With respect to the accessible portions of the ice condenser crane wall and accessible portions of the ice condenser structural concrete floor, Duke disagrees with the staff conclusion that these structural components require aging management for the period of extended operation for the same reasons that Duke provided in its March 11, 2002 response to RAI 3.5-6 and the response to Open Item 3.5-1 provided above.

Nevertheless and as a practical matter in order to support the timely resolution of this open item and the completion of the license renewal review on schedule, Duke will not challenge this issue further. Periodic inspections of the accessible portions of the crane wall and ice condenser structural concrete floor will be performed during the period of extended operation as part of the Inspection Program for Civil Engineering Structures and Components. No revisions to the UFSAR Supplement for either McGuire or Catawba is [sic] required in response to Open Item 3.5-3.

Since the ice condenser wear slab does not perform an intended function that meets the license renewal scoping criteria specified in 10 CFR 54.4, the staff agrees with the applicant's finding that the wear slab should not have been included within the scope of license renewal. The staff's review of this item is documented in Section 2.4.1.3.2 of this SER. In addition, since the applicant has committed to manage the aging effects for the accessible portions of the crane wall and ice condenser structural concrete floor during the period of extended operation (as indicated in its response to SER open item 3.5-1), the staff considers open item 3.5-3 to be closed.

<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 LRA 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 areas 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 AMPs 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.

Elastomers: 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. In its November 14, 2002, response to SER open item 2.3-3, the applicant identified cracking and shrinkage of structural sealant for structural members of the annulus. The staff concurs with applicant's identification of these two aging effects for structural sealant, which is treated as a subcomponent of the structural members of the annulus.

3.5.1.2.2 Aging Management Programs

Table 3.5-1 of the LRA credits the following AMPs 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
- Divider Barrier Seal Inspection and Testing Program
- Technical Specification SR 3.6.16.3 Visual Inspection

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified the Ventilation Area Pressure Boundary Sealants Inspection to manage the effects of cracking and shrinkage of structural sealant due to exposure to ambient conditions.

Of the above AMPs, the Containment Leak Rate Testing Program, Containment ISI Plan — IWE, Fluid Leak Management Program, Inspection Program for Civil Engineering Structures and Components, and Ventilation Area Pressure Boundary Sealants Inspection are credited with managing the aging of several components in different structures and systems and are, therefore, considered common AMPs. 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 AMPs is documented in Section 3.0 of the SER. The staff's evaluation of the Ice Condenser Inspections, Divider Barrier Seal Inspection and Testing Program, and Technical Specification SR 3.6.16.3 Visual Inspection AMPs are given below.

Ice Condenser Inspections

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 LRA Appendix B 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 no preventive actions are 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 LRA Appendix B describes the monitoring and trending. The Ice Basket Inspection requires a visual inspection performed at a 40-month 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 LRA Appendix B and the summary description in the FSAR supplement in LRA Appendix A. 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 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 LRA Appendix B 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 LRA Appendix B 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 LRA Appendix B 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 inspections and testing are 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 preventive actions taken as part of this program, and the staff did not identify the need for any preventive 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 LRA Appendix B states that cracking and change in material properties of elastomeric seals are detected through visual examinations and coupon testing. The inspections and testing are 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 LRA Appendix B 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 LRA Appendix B 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 LRA Appendix B. 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 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).

Technical Specification SR 3.6.16.3 Visual Inspection

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 LRA Appendix B, with managing this aging effect. SR 3.6.16.3 requires that the applicant perform a visual inspection of the exposed interior and exterior surfaces of the reactor building three times every 10 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 LRA Appendix B 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 LRA Appendix B 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 of the exposed interior and exterior surfaces of the reactor building three times every 10 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 Inspection 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 the structure's 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 LRA Appendix B 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 SR provides advance indication of deterioration of the concrete structural integrity of the reactor building. The frequency of the inspection is three times every 10 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 10-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 TSSR 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 inches up the parapet wall and 18 inches 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 LRA Appendix B, 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 LRA Table 3.5.1, as well as the applicable aging management program descriptions in LRA Appendix B. On the basis of its review, and with the resolution of SER 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) AMPs 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 (including control building, diesel generator buildings, fuel buildings, groundwater drainage system, main steam doghouses, and the UHI tank building (Catawba only)
- 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.

In response to open item 2.5-1, the applicant provided, by letter dated June 26, 2002, AMR results for the passive, long-lived structures and components associated with the offsite power path. During a meeting with the applicant on September 18, 2002 (summarized in a memorandum dated November 18, 2002), the staff indicated that, since no aging effects were specified for concrete structures and components identified in the June 26, 2002, AMR results tables, these concrete structures and components (which the staff believed were subject to aging effects) were additional examples of open item 3.5-1. In subsequent electronic correspondence with the applicant dated October 10, 2002 (ADAMS Accession No. ML023290464), the staff requested that the applicant present revised AMR results tables from the LRA.

By letter dated October 28, 2002, the applicant submitted revised LRA Tables 3.5-1, 3.5-2, and 3.5-3 to indicate the additional passive, long-lived structures and components associated with the offsite power path that were brought into the scope of license renewal. The structural components included concrete equipment pads, foundations, trenches, and reinforced walls, columns, and floor slabs. Structural steel components included anchorages, checkered plates, embedments, expansion anchors, beams, columns, plates, and trusses.

In a letter dated November 14, 2002, the applicant submitted its response to SER open item 2.3-3 pertaining to the applicant's treatment of structural sealants (subcomponents of structural members) in certain ventilation system applications for which pressure boundary integrity was an intended function (e.g., the fuel handling building, the auxiliary building, and the control area). The applicant identified cracking and shrinkage of structural sealants due to exposure to ambient conditions as potential aging effects. The applicant also provided the Ventilation Area Pressure Boundary Sealants Inspection, which it credited to monitor these aging effects.

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 evironment
- 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

In a letter dated June 26, 2002, the applicant provided AMR results tables for the passive, long-lived structures and components associated with the offsite power path in response to RAIs 2.5-1 and 2.5-2. The applicant subsequently included these structures and components in revised LRA Tables 3.5-1, 3.5-2, and 3.5-3, which were submitted to the staff by letter dated October 28, 2002. In its resolution of SER open item 3.5-1 (documented in Section 3.5.1.2.1 of this SER), the applicant identified cracking, change in material properties, and loss of material as applicable aging effects for the above-grade concrete components. For steel components, the applicant identified loss of material as an applicable aging effect for components in a sheltered or external environment. In its November 14, 2002, response to SER open item 2.3-3, the applicant identified cracking and shrinkage of structural sealant due to exposure to ambient conditions.

3.5.2.1.2 Aging Management Programs

Table 3.5-2 of the LRA credits the following AMPs with managing the identified aging effects for the components in structures outside the reactor building:

- Boraflex Monitoring Program
- Flood Barrier Inspection
- 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

In its October 28, 2002, response to SER open item 3.5-1, which included the passive, long-lived structures and components associated with the offsite power path (provided by the applicant in response to SER open item 2.5-1), the applicant committed to manage the aging of these electrical components through its Inspection Program for Civil Engineering Structures and Components.

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified the Ventilation Area Pressure Boundary Sealants Inspection to manage the effects of cracking and shrinkage of structural sealant due to exposure to ambient conditions.

A description of these AMPs is provided in Appendix B of the LRA or subsequent correspondence from the applicant. The applicant concludes that the effects of aging associated with the components in structures outside the reactor building will be adequately managed by these AMPs 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 LRA Section 2.4, "Scoping and Screening Results: Structures," and the applicable aging management program descriptions provided in LRA Appendix B 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 AMPs 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 AMPs 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 three 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.

Concrete: 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 of this SER, 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 LRA 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 LRA 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 of this SER, 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 AMPs 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 was identified in Section 3.5.1.2.1 of this SER as open item 3.5-1.

The applicant resolved open item 3.5-1 by committing to manage the aging of accessible concrete components during the period of extended operation. Specifically, the applicant committed to manage loss of material, cracking, and change in material properties for accessible concrete structural components using its Inspection Program for Civil Engineering Structures and Components. For the passive, long-lived structures and components associated with the offsite power path that were brought into the scope of license renewal, the applicant committed to manage loss of material, cracking, and change in material properties using its Inspection Program for Civil Engineering Structures and Components. This commitment is consistent with the applicant's aging management of other accessible concrete structural components as proposed in response to open item 3.5-1. Resolution of open item 3.5-1 is documented in further detail in Section 3.5.1.2.1 of this SER.

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 of this SER. 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 of this SER as open item 3.5-2.

In response to open item 3.5-2, the applicant stated that it did not commit to initiate a corrective action in the event of a potential change to the site environment, resulting from a chemical release during the period of extended operation, because such an event was not postulated. The applicant stated that it is not credible to postulate that some environmental event will occur in the future that would affect the quality of groundwater in the vicinity of Catawba or McGuire. Such a change in the environment due to a chemical release would be an abnormal event. As stated in NUREG-1800, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," aging effects from abnormal events need not be postulated specifically for license renewal. The staff concurs with the applicant's determination that a potential change to the site environment resulting from a chemical release during the period of extended operation would be an abnormal event. Therefore, such a chemical release would not need to be included in an aging management review, and the staff considers open item 3.5-2 to be closed.

<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

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified cracking and shrinkage of structural sealant due to exposure to ambient conditions.

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 AMPs with managing the identified aging effects for the components in structures outside the reactor building:

- Boraflex Monitoring Program
- Flood Barrier Inspection
- 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

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified the Ventilation Area Pressure Boundary Sealants Inspection to manage the effects of cracking and shrinkage of structural sealant due to exposure to ambient conditions.

The latter five AMPs 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) and Ventilation Area Pressure Boundary Sealants Inspection are credited with managing the aging of several components in different structures and systems and are, therefore, considered common AMPs. 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 AMPs 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 AMPs follows.

Boraflex Monitoring Program

The applicant described its Boraflex Monitoring Program in Section B.3.3 of LRA Appendix B. 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 1 and 2 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 breakdown of the polymer matrix and eventual release of boron carbide into the spent fuel pool (SFP). However, based on the known mechanism governing the polymer matrix breakdown, the staff requested information related to the SFP clean up 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 1 percent. The applicant also stated that its 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 3 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 (GL) 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 B.3.3 of LRA Appendix B. 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).

<u>Flood Barrier Inspection</u>

The applicant described its Flood Barrier Inspection program in Section B.3.13 of LRA Appendix B. 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 used only 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 LRA Appendix B 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 LRA Appendix B 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.

[Program Scope] Section B.3.13 of LRA Appendix B 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 applicable only to McGuire; at Catawba, the flood barrier seals inspections are implemented through the Inspection Program for Civil Engineering Structures and Components. This is acceptable to the staff.

[Preventive 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.3.13 of LRA Appendix B 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 LRA Appendix B 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 LRA Appendix B 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 LRA Appendix B 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 judgment 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 LRA Appendix B 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 LRA Appendix A, 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 LRA Appendix B and, therefore, acceptable.

In conclusion, the staff reviewed the information provided in Section B.3.13 of LRA Appendix B and the summary description of the flood barrier seal inspection activities in LRA Appendix A, 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 LRA Appendix B. The applicant credits this inspection activity with managing the potential aging of the SNSWP dams. The staff reviewed Section B.3.30 of LRA Appendix B 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 LRA Appendix B 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 dam 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 SNSWP 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 riprap, 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 core 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 (RG) 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 SNSWP 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.

[Program Scope] Section B.3.30 of LRA Appendix B 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.

[Preventive 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.3.30 of LRA Appendix B 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 riprap, 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 LRA Appendix B 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 riprap, 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 LRA Appendix B 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 LRA Appendix B states that the acceptance criteria are 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 LRA Appendix B describes the plant-specific operating experience related to the inspections of the SNSWP dam. 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 of material of the SNSWP dams at Catawba and McGuire. The staff concurs that the program as described and the inspection frequency provide reasonable assurance that the intended function of the SNSWP dam 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 for McGuire and SR 3.7.9.3 for Catawba. The staff reviewed the TS and finds the description consistent with Section B.3.30 of LRA Appendix B and, therefore, acceptable.

In conclusion, the staff reviewed the information provided in Section B.3.30 of LRA Appendix B 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 LRA Table 3.5.2, as well as the applicable aging management program descriptions in LRA Appendix B. On the basis of its review, and with the resolution 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) AMPs 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 an AMR, are steel or stainless steel and are located in all of the structures within the scope of license renewal for McGuire and Catawba.

The component and equipment supports are exposed to external, sheltered, reactor building, 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 AMPs 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 AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in the reactor building and other structures will be adequately managed by these AMPs 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 LRA Section 2.4, "Scoping and Screening Results: Structures," and the applicable aging management program and activity descriptions provided in LRA Appendix B 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 AMPs credited for the aging management of the component supports at McGuire and Catawba. 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 AMPs 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 of the LRA 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 LRA 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 LRA Table 3.5-3 that do not have any applicable aging effects.

In its response, dated March 11, 2002, the applicant stated that metal housing systems, such as control boards, electrical and instrument panels, enclosures, etc., that are constructed of factory baked painted steel or galvanized sheet metal do not have a tendency to age with time[7]. Industry operating experience with metal housing systems indicates that they have performed without failure to the present[8]. 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

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[7] "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

[8] "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

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 LRA Table 3.5-3. The staff finds that the applicant's approach for evaluating the applicable aging effects for component supports as described in LRA Table 3.5-3 is 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 AMPs 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 AMPs listed above (the Fluid Leak Management Program, the Inspection Program for Civil Engineering Structures and Components, the ISI Plan — Subsection IWF, the Underwater Inspection of Nuclear Service Water Structures, and the Chemistry Control Program) are credited with managing the aging of several components in different structures and systems and are, therefore, considered common AMPs. 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 AMPs is documented in Section 3.0 of the SER. The staff's evaluation of the Battery Rack Inspections and the Crane Inspection Programs AMPs follows.

Battery Rack Inspections

The applicant described the Battery Rack Inspections program in Section B.3.2 of LRA Appendix B. 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 LRA Appendix B 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 LRA Appendix B states that the purpose of the Battery Rack Inspections 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 LRA Appendix B 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 Inspections 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 — TSSR 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 Inspections 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.

[Program Scope] 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 preventive actions taken as part of this program, and the staff did not identify the need for any preventive 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 subcomponents (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 subcomponents, for physical damage or abnormal deterioration, including loss of material due to corrosion. The applicant further stated that the inspection acceptance criterion for loss of material in the procedure is "no significant amount of corrosion or rust spots visible." Physical damage or deterioration is 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 affect 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 LRA Appendix B 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 are "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 subcomponents.

[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 LRA Appendix A-1 and LRA Appendix A-2 for McGuire and Catawba, respectively, and compared them with Section B.3.2 of LRA Appendix B. 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 was requested to provide a summary description characterizing the important elements of the Battery Rack Inspections from Section B.3.2 of LRA Appendix B and the applicant's response to RAI B.3.2-1, as described above. This issue was characterized as SER open item 3.5-4. In its response dated October 2, 2002, the applicant provided revisions to Table 18-1 and Section 18.3 of the FSAR supplements for McGuire and Catawba. The revised FSAR supplements stated that inspections of the structural supports and anchorages of the battery racks would be performed. The staff finds the applicant's revisions acceptable, since inspection of these specific subcomponents of the battery rack structures is specified. Therefore, open item 3.5-4 is closed.

In conclusion, the staff reviewed the information provided in Section B.3.2 of LRA Appendix B 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).

Crane Inspection Program

The applicant describes its Crane Inspection Program activities in Section B.3.10 of LRA Appendix B. 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 LRA Appendix B to determine whether the applicant had demonstrated that the Crane Inspection Program 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 LRA Appendix B 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, "Overhead and Gantry Cranes, Section 2-2, Safety Standards for Cableways, Cranes, Derricks, Hoists, Hooks, Jacks, and Slings," ANSI B30.16, "Overhead Hoists (Underhung)," and the requirements contained in 29 CFR Chapter XVII, 1910.179.

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 LRA Appendix B states 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 LRA Appendix B 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 are acceptable and agrees that no actions are necessary for this program to trend inspection or test results.

[Acceptance Criteria] Section B.3.10 of LRA Appendix B 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 has 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] 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. 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 LRA Appendix B 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 supplements. The applicant was requested to update the FSAR supplements to incorporate those standards and guidelines. This issue was characterized as SER open item 3.5-5. In its response dated October 2, 2002, the applicant provided revised summary descriptions of the Monitoring and Trending attribute for this inspection program. For McGuire and Catawba, revised FSAR supplements incorporated the codes and standards listed in the RAI response. The staff finds the applicant's revised the FSAR supplements acceptable because they ensure that the program will be governed by these codes and standards. Therefore, open item 3.5-5 is closed.

In conclusion, the staff reviewed the information provided in Section B.3.10 of LRA Appendix B 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 Table 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 of the LRA 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 a structural component, such as a 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. Most 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 identified.

3.5.4.2 Aging Management Programs

Loss of material of structural components including the bolting is managed by the Inservice 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 Inservice Inspection Plan — Subsection

IWF or the Inspection Program for Civil Engineering Structures and Components. The Inservice 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 Inservice Inspection Plan — Subsection IWF program and the Inspection Program for Civil Engineering Structures are 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 Components

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 effects of aging for 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 spaces" 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, aging of installed cables and connections is bounded by the cable and connection insulation materials that are specified 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 LRA 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 LRA 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; these 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 the 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) is less severe than the plant design environment. However, in a limited number of localized areas, the actual environments may be more severe than the 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 a certain plant area with significantly more severe conditions 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.

In a letter dated May 16, 2002, the staff forwarded to the Nuclear Energy Institute (NEI) and Union of Concerned Scientists a proposed interim staff guidance (ISG) document on screening of electrical fuse holders. The ISG stated that fuse holders should be scoped, screened, and subject to an AMR in the same manner as terminal blocks and other types of electrical connections that also meet the criteria specified in 10 CFR 54.4 and 54.21. This position applies only to fuse holders that are not part of a larger assembly such as switchgear, power supplies, power inverters, battery chargers, circuit boards, etc. Fuse holders in these types of active components would be considered piece-parts of the larger assembly and not subject to an AMR.

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

Operating experience as documented in NUREG-1760, "Aging Assessment of Safety-Related Fuses Used in Low- and Medium-Voltage Applications in Nuclear Power Plants," indicates that aging stressors such as vibration, thermal cycling, electrical transients, mechanical stress, fatigue, corrosion, chemical contamination, or oxidation of the connection surfaces can result in fuse holder failure. The final staff position on this issue is under development. In a letter dater November 13, 2002, the staff requested the applicant to commit to implement, at McGuire and Catawba, the final resolution of the ISG.

In its response to the staff's request, dated November 18, 2002, the applicant provided the following commitment:

> For McGuire, Duke commits to implement the final version of the fuse holder interim staff guidance (initially provided to NEI by letter dated May 16, 2002 and when finalized by the staff) by June 12, 2021 (the end of the initial license of McGuire Unit 1).
>
> For Catawba, Duke commits to implement the final version of the fuse holder interim staff guidance (initially provided to NEI by letter dated May 16, 2002 and when finalized by the staff) by December 6, 2024 (the end of the initial license of Catawba Unit 1).

This commitment was included in a table of commitments submitted by the applicant in a letter dated December 16, 2002. The table of commitments is provided in Appendix D of this SER. The staff found the applicant's response acceptable because it commits to implement the final resolution of the ISG before the period of extended operation begins at McGuire and Catawba.

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 elements rather than details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects 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) program scope, (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, and (10) 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.

[Program 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 viewed 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 include 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 exception of low-level instrumentation circuits, the scope of the program is acceptable because it includes all non-EQ insulated cables and connections that are subject to a 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, and 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 precursors indicative 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 plant 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 a means for monitoring the applicable aging effects for accessible in-scope non-EQ insulated cables and connections.

[Detection of Aging Effects] The application states that 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 effect when cables and connections are exposed to an adverse localized environment.

[Monitoring and 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 inspection 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 and by June 12, 2021 (the end of the initial license for McGuire 1). 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 and by December 6, 2024 (the end of the initial license for Catawba 1). The staff finds that a 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 an indicator that can be visually monitored to identify aging effects of accessible cables and connections and includes inaccessible cables and connections in its corrective actions.

[Acceptance Criteria] The acceptance criteria for inspection performed per the Non-EQ Insulated Cables and Connections Aging Management Program are 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 3 feet of) steam generators, pressurizers 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 are 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.

<u>Low-Level Instrumentation Circuits</u>

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 the 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 the cables' 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[9] 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) — Advantages/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, an 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 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 report referred to by the applicant assumes only dry conditions where cable cracking occurs. V.N. Shah and P.E. MacDonald, on page 855 of "Aging and Life Extension of Major Light Water Reactor Components,"[10] state that breaks in insulation systems that are dry and clear are normally not detectable with insulation resistance tests of 1000 volts or less. Insulation resistance tests can detect some types of gross insulation

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[9] 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

[10] "Aging and Life Extension of Major Light Water Reactor Components," edited by V.N. Shah and P.E. MacDonald, 1993, Elsevier Science Publishers

damage, cracking of 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 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, an 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.

In a 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 found this change to the Corrective Actions and Confirmation Process element of the Non-EQ Insulated Cables and Connections Aging Management Program acceptable since the applicant agreed to address the potential for moisture-induced signal degradation or failure. The staff noted that the FSAR supplement needed to be updated to reflect this change and characterized this issue as confirmatory item 3.6.1-1.

In its response to confirmatory item 3.6.1-1, dated October 2, 2002, the applicant stated that it will add the following statement to the Corrective Actions and Confirmation Process of the Non-EQ Insulated Cables and Connections Aging Management Program summary description contained in Chapter 18 of each station's FSAR supplement: "Corrective action should consider the potential for moisture in the area of degradation."

The staff found the applicant's response to confirmatory item 3.6.1-1 acceptable because the modification to the Non-EQ Insulated Cable and Connections Aging Management Program is reflected in the revised FSAR supplement.

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 from 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 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 1 to 5 kV 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 for the visual inspection approach.

The staff indicated that the applicant should provide a technical justification to demonstrate that visual inspection will be effective in detecting damage to high-range radiation monitor and neutron monitoring instrumentation cables before current leakage can affect instrument loop accuracy. This issue was characterized as SER open item 3.6.1-1.

In its response to open item 3.6.1-1, dated October 2, 2002, the applicant reiterated its view that visual inspections have proven to be effective and useful because visual inspections have revealed potential problems. The applicant asserted that problems that have not developed to the point of component failure can be identified through visual inspection. The applicant also stated that 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, also are easily detectable by visual inspection. Visual inspection can detect aging degradation early in the aging process before significant aging degradation or failure has occurred.

The applicant provided three examples of cable installation configuration that were identified through visual inspection that would not have been otherwise identified. In one example, the applicant stated that, during Oconee visual inspection walkdowns, the power and control cables for an auxiliary steam (AS) system valve were found lying on top of an uninsulated portion of the pipe. Contact with the hot steam pipe eventually would have degraded the cables, potentially resulting in failure. The valve was installed near the ceiling in the turbine building, some 30 feet above the floor, and would have been found only through dedicated visual inspections. In another example, the applicant stated that a visual inspection walkdown also revealed a small cable tray with safety-related cables that were installed near the ceiling in close proximity to a high-intensity light fixture. The applicant had identified a concentric ring on the bottom of the cables. At the time this was identified, the applicant could not determine if the rings were cast by variations in the light shining on the cables or if heat generated from the lamp had discolored the cable jackets. In a third example, the applicant had identified (during an Oconee walkdown) instrumentation cables in a cable tray in the reactor building that was installed directly over a feedwater line. The heat escaping from a shield wall penetration sleeve around the feedwater pipe was accelerating the aging of the cable insulation. The visual signs that indicated aging degradation of cables in the tray were the way the cables "sagged" between the cable tray lattice. The applicant also stated that many of the cable jackets looked "dry" and had surface cracks. The cables in the tray were tested, and all cables were fully functional.

As previously discussed, the staff agreed with the applicant that, for low-voltage, low-signal cables, visual inspection can be an effective means to detect age-related degradation due to adverse localized environments. However, the staff does not believe that this is necessarily the case for high-range radiation monitor and neutron monitoring system cables. These circuits operate with low-level logarithmic signals that are sensitive to relatively small changes in signal strength, and they operate at high voltages that could create larger leakage currents if the voltage is impressed across associated cables and connections. The staff did not have reasonable assurance that visual inspection will be effective in detecting damage before current leakage can affect instrument loop accuracy. Therefore, the staff issued a letter dated November 13, 2002, to notify the applicant that open item 3.6.1-1 remained unresolved. The proposed visual inspection was not consistent with the staff's position on previous LRA reviews. However, loop calibration tests, which are routinely performed in accordance with existing technical specification surveillance requirements at McGuire and Catawba, might be considered acceptable for monitoring aging of cables during the period of extended operation and involve minimal regulatory burden.

In its response dated November 14, 2002, the applicant stated that it will implement the License Renewal Program for Non-EQ Neutron Flux Instrumentation Circuits specifically to address the staff's open item 3.6.1-1. The scope of this program included only non-EQ neutron flux instrumentation cables that are within the scope of license renewal. The applicant indicated that other cables under discussion here, high-range radiation monitors/cables and the wide-range neutron flux monitors/cables, were included in the McGuire and Catawba EQ program and already covered for license renewal by this program. After reviewing the License Renewal Program for Non-EQ Neutron Flux Instrumentation Circuits, the staff contacted the applicant by phone and requested the applicant to indicate whether or not the high-range radiation monitoring cables were included within the scope of this program. During the call, the applicant indicated that it had included only the cables used in non-EQ neutron flux instrumentation circuits within the scope of 10 CFR 54.4. Non-EQ means not subject to 10 CFR 50.49 EQ requirements. The applicant stated that it excluded the high-range radiation monitors/cables and the wide-range neutron flux monitors/cables from the scope of the AMP because they are included in the EQ program. However, the staff noted that these cables are run inside and outside containment, and that the portions of the cables that are outside the containment are non-EQ and should be included in the scope of the AMP.

In a letter dated November 21, 2002, the applicant indicated that, since the scope of this program did not include the high-range radiation monitoring cables, a different program had been developed. The License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits was provided in place of its License Renewal Program for Non-EQ Neutron Flux Instrumentation Circuits. The applicant indicated that the November 21, 2002, response superceded the November 14, 2002, response. The staff found the applicant's November 21, 2002, response to SER open item 3.6.1-1 acceptable because the applicant will implement an AMP to monitor the aging of these sensitive cables. Therefore, open item 3.6.1-1 is closed.

The License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits was evaluated by the staff to establish reasonable assurance that the intended function of electrical cables that are (1) not subject to the EQ requirement of 10 CFR 50.49, and (2) are used in circuits with sensitive, low-level signals exposed to adverse localized environments caused by heat, radiation, or moisture will be maintained consistent with the CLB through the period of extended operation.

License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits. The License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits is generically applicable to both McGuire and Catawba, except as otherwise noted. The staff's evaluation of the applicant's AMP focused on the program elements rather than details of specific plant procedures. To determine whether the applicant's aging management program is adequate to manage the effects 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, (7) corrective action, (8) confirmation process, (9) administrative controls, and (10) 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 elements follows.

[Program Scope] In its letter dated November 21, 2002, the applicant described the scope of the License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits as follows:

> [Scope] The scope includes the non-EQ cables used in neutron flux instrumentation circuits and high-range radiation instrumentation circuits within the scope of 10 CFR 54.4. Non-EQ means not subject to 10 CFR 50.49 Environmental Qualification requirements.

The staff found the applicant's scope attribute description acceptable because the scope specifically includes the high-range radiation monitoring and wide-range neutron flux cables that are outside the containment.

[Preventive Actions] No actions are taken as part of the License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits to prevent aging effects or to mitigate aging degradation, and the staff did not identify the need for such actions.

[Parameters Monitored or Inspected] The parameters monitored are determined from the plant technical specification and are specific to each instrumentation circuit, as documented in surveillance procedures. The staff found this approach to be acceptable because it provides means for monitoring the applicable aging effects for in-scope instrumentation cables.

[Detection of Aging Effects] In accordance with the information provided in Monitoring and Trending, the License Renewal Program for High-range Radiation and Neutron Flux Instrumentation Circuits provides sufficient indication of the need for corrective actions. The staff found it acceptable on the basis that the calibration program identifies the need for corrective actions by monitoring key parameters based on acceptance criteria.

[Monitoring and Trending] The methods for performing the License Renewal Program for High-range Radiation and Neutron Flux Instrumentation Circuits are described in Sections 3.3.1 and 3.3.3 of each station's TS. Instrumentation circuit surveillances currently required by plant TS are performed at the specified surveillance frequency and provide sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation circuit performance. Trending actions are not included as part of this program because the ability to trend test results is dependent on the specific type of test chosen. Although not a requirement, test results that can be trended will provide additional information about the rate of degradation.

The staff found that the normal surveillance frequency specified in the plant TS provides reasonable assurance that aging degradation of high-range radiation and neutron flux instrumentation circuits will be detected before a loss of their intended functions occurs. The staff also found the absence of trending acceptable; however, the staff notes that trending should be performed by the applicant when the specific type of test makes this possible because it provides additional information about the condition of the cables.

[Acceptance Criteria] The acceptance criteria for each surveillance are documented in surveillance procedures. The staff found the acceptance criteria acceptable because the surveillance procedures are used to demonstrate that surveillance requirements specified in ITS 3.3.1 and 3.3.3 are met. The activities described in the McGuire and Catawba TS should ensure that intended functions of the cables used in instrumentation circuits are maintained under all CLB design conditions during the period of extended operation.

[Operating Experience] Plant-specific and industry operating experience have shown that adverse circuit indications found during routine surveillance can be caused by degradation of the instrumentation circuit cable and are possible indications of potential cable degradation. The staff found it acceptable because the calibration program will detect the aging degradation of instrumentation circuit cables that are installed in the adverse localized environments.

FSAR Supplement. In its November 21, 2002, response to SER open item 3.6.1-1, the applicant stated that it would revise the Table 18-1 of each station's UFSAR to insert the following item:

Topic	Application Location	UFSAR/ITS
License Renewal Program for High-range Radiation and Neutron Flux Instrumentation Circuits	NA	ITS 3.3.1 ITS 3.3.3

The staff found the proposed FSAR supplement acceptable because ITS 3.3.1 and 3.3.3 provide appropriate acceptance criteria, surveillance frequency, and test objectives for the AMP. The level of detail provided in the ITS is equivalent to that which is specified in the staff's review guidance (NUREG-1800) and, therefore, is an adequate summary of the program activities as required by 10 CFR 54.21(d).

On the basis of its review, the staff found that the program established reasonable assurance that the intended function of electrical cables that are (1) not subject to the EQ requirement of 10 CFR 50.49, and (2) are used in circuits with sensitive, low-level signals exposed to adverse localized environments caused by heat, radiation, or moisture will be maintained consistent with the CLB through the period of extended operation.

3.6.1.3 Conclusions

Based on the review of the LRA and the applicant's responses to the staff's RAI and SER open and confirmatory items, the staff concludes that the implementation of Non-EQ Insulated Cables and Connections Aging Management Program and License Renewal Program for High-range Radiation and Neutron Flux Instrumentation Circuits will provide reasonable assurance that the aging effects associated with heat, radiation, and moisture for 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 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 last 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 criterion documented in UFSAR Section 8.3.1.4.5.1, "Cable Installation," that conduit runs 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 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 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 the 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's AMPs are adequate to manage the effects 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, (7) corrective action, (8) confirmation process, (9) administrative controls, and (10) 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 elements follows.

[Program 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., 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 are 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 a 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 were 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 Cables 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 (SAND 96-0344, Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cables and Termination) states the following 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 exposed 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 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 "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 and 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 is acceptable since the applicant has agreed to eliminate the qualifier "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, and documented its evaluation in the applicable paragraphs that follow in this SER section. 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 Program 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 or 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 the 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 effects. 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 and 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 are 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 definitions 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 actions 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 and 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 the 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 this revision acceptable because, as long as the applicant tests the medium-voltage cables that are exposed to significant voltage and standing water for any period of time every 10 years, no preventive 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 was unable to determine if the test to be performed will be an appropriate test that has been proven to accurately assess the cable condition with regard to water treeing. In a letter dated October 19, 2002, the staff requested the applicant to modify this attribute to indicate that the test to be performed will be a proven test for detecting deterioration of insulation systems due to wetting. The staff requested this modification so that it can make a reasonable assurance finding that the test will be capable of detecting insulation degradation and that the effects of aging on inaccessible non-EQ medium-voltage cables will be adequately managed, so that the intended function will be maintained in accordance with the requirement of 10 CFR 54.21(a)(3).

In its response to the staff request, dated November 5, 2002, the applicant provided a revision to the Parameters Monitored or Inspected attribute of the summary description of the Inaccessible Non-EQ Medium-Voltage Cables AMP in the FSAR supplement of each station. The revision is as follows:

> Parameters Monitored or Inspected — Medium-voltage cables within the scope of the Inaccessible Non-EQ Medium-Voltage Cable 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 and will be a proven test for providing an indication of the condition of the conductor insulation related to aging effects caused by moisture and voltage stress. Each test performed for a cable may be a different type of test.

The staff found the applicant's response acceptable because the test to be performed will be a proven test for detecting deterioration of an insulation system due to wetting.

[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's test schedule is acceptable.

[Monitoring and 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 Program Scope would not be met). Since 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 (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.

In its response dated July 9, 2002, the applicant stated the following:

> The alternative visual inspection 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 and 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 does 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 are 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 was characterized as confirmatory item 3.6.2-1. In its response to the confirmatory item, dated October 2, 2002, the applicant stated that it will insert the summary description of the revised Inaccessible Non-EQ Medium Voltage Cables AMP (as provided in Duke letters dated July 9, 2002, Attachment 1, pages 89-91, and November 5, 2002) in each station's FSAR supplement in place of the program description previously provided. The staff found the applicant's response to confirmatory item 3.6.2-1 acceptable because the change to the program proposed by the applicant will be reflected in the FSAR supplement.

3.6.2.3 Conclusions

On the basis of the staff's evaluation described above, the staff finds that there is reasonable assurance that the effects of aging of 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 need 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 LRA Appendix B.

3.6.3.2 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 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 the 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 an applicable aging effect 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 Conclusions

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 Aging Management of Electrical Components Required for Station Blackout (SBO)

In a letter dated January 17, 2002, the staff requested additional information concerning Section 2.5 of the LRA. The staff requested the applicant to clarify why switchyard systems are not relied on in safety analyses or plant evaluations to perform a function in the recovery from an SBO event. In its response dated March 8, 2002, the applicant stated that, based on the results of a recent review of plant documents, McGuire and Catawba components that are part of the power path for offsite power from the switchyard are within the scope of license renewal in accordance with the SBO scoping criterion, 54.4(a)(3). This power path includes portions of the power path from the unit power circuit breakers (PCBs) in the respective switchyard to the safety-related buses in each plant. The power path includes portions of (1) the switchyard systems, (2) the unit main power system, and (3) the nonsegregated-phase bus in the 6.9 kV normal auxiliary power system of each station. In its March 8, 2002, response, the applicant committed to provide the results of the aging management review for the long-lived, passive structures and components associated with the offsite power path by June 30, 2002.

In a letter dated June 26, 2002, the applicant provided the results of its scoping and screening review and AMR review for electrical components and structures associated with the offsite power path. The AMR results were generically applicable for McGuire and Catawba. The staff reviewed the AMR results to determine whether the applicant had demonstrated that the effects of aging for the electrical structures and components in the power recovery path for SBO events will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.4.1 AMR Results for Isolated-Phase Bus and Nonsegregated-Phase Bus

The AMR results for isolated-phase bus and nonsegregated-phase bus are summarized in Attachment 1, Section 5.3, "Aging Management Review Results Table," of the June 26, 2002, letter from the applicant.

3.6.4.1.1 Aging Effects

The applicant stated that aging management review for McGuire and Catawba isolated-phase bus and nonsegregated-phase bus follows the guidance provided in the EPRI License Renewal Electrical Handbook and is consistent with the guidance provided in NEI 95-10 and the previous review performed for Oconee. Isolated-phase bus and nonsegregated-phase bus descriptions are provided in Chapter 8 of the License Renewal Electrical Handbook.

The applicant stated that McGuire and Catawba isolated-phase bus and nonsegregated-phase bus have three main parts or assemblies: the conductor, the conductor support (insulator), and the bus enclosure. Where nonsegregated-phase bus passes through an outside wall, a wall bushing assembly is used to provide a thermal barrier. As confirmed through a review of manufacturer's drawings and personnel interviews, McGuire and Catawba isolated-phase bus and nonsegregated-phase bus are similar in design, construction, and materials to the Oconee phase bus described in Section 3.6.2.1 of the Oconee Application with two notable differences. One difference is that the aluminum conductor for the bus section is welded rather than bolted together, and the conductor is bolted only where braided conductors are installed to prevent the propagation of vibration to the rigid conductor. There are fewer bolted connections at McGuire and Catawba than at Oconee. The other difference is that the aluminum bus and braided mating surfaces are silver plated. This raises the potential for formation of silver oxide at the connections for McGuire and Catawba rather than the formation of aluminum oxide, which exists for Oconee. Other differences between the Oconee, McGuire, and Catawba bus are not significant to the AMR.

The applicant stated that, based on industry literature, plant operating experience, and the Oconee application review, the potential aging effects identified in Table 2 of the LRA are required to be included in the phase bus aging management review. This review included industry operating experience reports for phase bus identified in Chapter 11 of the License Renewal Electrical Handbook. This aging effects identification process is consistent with the process used in Section 3.6 of the Oconee application.

Connection Surface Oxidation for Aluminum Conductor Phase Bus. The applicant states that aluminum conductors of the bus section are welded except where braided conductors are used to connect the bus to another component. The aluminum mating surfaces at these connections are coated with copper and then silver plated. The silver plating is highly conductive but does not make a good contact surface since silver exposed to air forms silver oxide on the surfaces. The surfaces are periodically cleaned (to remove any existing silver oxide) and covered with a grease to prevent air from contacting the mating surfaces. The grease precludes oxidation of the silver surface, thereby maintaining good conductivity at the bus connections. The grease is a consumable that is replaced during each routine maintenance of the bus. Therefore, the applicant concludes that applicable aging effects for the aluminum bus connections when exposed to their service conditions for the extended period of operation are adequately addressed through maintenance.

Temperature for Silicone Caulk for Phase Bus. The applicant stated that silicone-rubber-based caulk is used to maintain spacing between the conductor and bushing in a wall bushing assembly. Silicone rubbers have a 60-year service-limiting temperature of 273 °F as documented in Table 9-1 of the License Renewal Electrical Handbook. The isolated-phase bus and nonsegregated-phase bus are installed in the turbine building, service building, and transformer yard, which have a bounding ambient design temperature of 110 °F and negligible radiation. Adding design ohmic heating to the ambient temperature puts the service condition for temperature at 226 °F, which is less than the 60-year service-limiting temperature of 273 °F for silicone rubber. Therefore, silicone rubber has no aging effects due to heat for the extended period of operation that will cause loss of component intended function.

Moisture for Steel Hardware for Phase Bus. The applicant stated that steel hardware (bolts, washers, nuts, etc.) is used on parts of the bus enclosure that are not welded. The enclosure and hardware exposed to external environment (precipitation) were factory coated to inhibit corrosion. Based on collective service experience at Oconee, McGuire, and Catawba (service of from 20 to over 30 years), no signs of corrosion or loss of material have been observed. Therefore, loss of material for steel hardware is not an applicable aging effect that will lead to a loss of intended function for the bus for the period of extended operation.

3.6.4.1.2 Aging Management Programs

The applicant stated that, based on its review of materials and service conditions, no applicable aging effects were identified. Therefore, McGuire and Catawba isolated-phase bus and nonsegregated-phase bus will perform their intended functions in accordance with CLB during the period of extended operation, and no aging management is required.

3.6.4.2 Staff Evaluation of AMR Results for Isolated-Phase Bus and Nonsegregated-Phase Bus

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 electrical components required for SBO at McGuire and Catawba nuclear stations. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on electrical components required for SBO will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.4.2.1 Aging Effects

The isolated-phase bus and nonsegregated-phase bus at McGuire and Catawba have three main parts or assemblies: the conductor, the conductor support (insulator), and the bus enclosure. Where nonsegregated-phase bus passes through an outside wall, a wall bushing assembly is used to provide a thermal barrier. The aluminum conductors of the bus sections are welded except where braided conductors are used to connect the bus to another component.

The aging mechanism for the aluminum conductor is connection surface oxidation. The aging effect is change in material properties leading to increased resistance and heating. The aluminum mating surfaces at these connections at McGuire and Catawba are coated with copper and then silver-plated. The silver plating is highly conductive but does not make a good contact surface, since silver exposed to air forms silver oxide on connection surfaces. The applicant stated that the surfaces are periodically cleaned to remove any existing silver oxide and covered with grease to prevent air from contacting the mating surfaces. The grease precludes oxidation of the silver surface, thereby maintaining a good conductivity at the bus connections. Grease is a consumable that is replaced during each routine maintenance of the bus. Therefore, no applicable aging effects are identified for the aluminum bus connections when exposed to the service conditions for the extended period of operation. The staff finds grease precludes oxidation of the connection mating surface, and no aging effects are applicable for aluminum conductor phase bus.

The aging mechanisms for silicone caulk for phase bus are temperature and radiation. The potential aging effect for silicone caulk requiring evaluation is change in material properties leading to loss of maintained spacing between the bus and bushing. Silicone-rubber-based caulk is used to maintain spacing between the conductor and bushing in a wall bushing assembly. The applicant stated that silicone rubbers have a 60-year service-limiting temperature of 273 °F. The isolated phase bus and nonsegregated-phase bus are installed in the turbine building, service building, and transformer yard, which have a bounding ambient design temperature of 110 °F and negligible radiation. Adding design ohmic heating to the ambient temperature puts the service condition for temperature at 226 °F, which is less than the 60-year service-limiting temperature of 273 °F for silicone rubber. Therefore, silicone rubber has no aging effects due to heat for the extended period of operation that will cause loss of component intended function. The staff finds because service conditions for silicone caulk is less than the 60-year service-limiting temperature, no aging effects are applicable to silicone caulk for the extended period of operation.

The aging mechanism for steel (enclosure hardware) is moisture. The potential aging effect is change in material properties (corrosion) leading to loss of function for the part. Steel (bolts, washers, nuts, etc.) is used on parts of the bus enclosure that are not welded. The enclosure and hardware exposed to external environment (precipitation) were factory-coated to inhibit corrosion. The applicant stated that based on collective service experience at Oconee, McGuire, and Catawba, no signs of corrosion or loss of material have been observed. Therefore, loss of material for steel hardware is not an applicable aging effect that will lead to a loss of intended function for the bus for the period of extended operation. The staff finds that enclosure and hardware exposed to external environment were factory coated to inhibit corrosion. Operating experience has also shown that no signs of corrosion or loss of material have been observed. Therefore, corrosion of phase bus enclosure is not an applicable aging effect at McGuire and Catawba.

3.6.4.2.2 Aging Management Programs

The staff concluded that no aging management program is required for isolated-phase bus and nonsegregated-phase bus because no aging effects are identified for isolated-phase bus and nonsegregated-phase bus.

3.6.4.3 Conclusions

Based on the review of the LRA, the staff concluded that no aging management program is required for isolated-phase bus and nonsegregated-phase bus. The applicant has demonstrated that there is a reasonable assurance that the McGuire and Catawba isolated-phase bus and nonsegregated-phase bus will perform their intended functions in accordance with the current license basis during the period of extended operation.

3.6.4.4 Aging Management Review Results for Transmission Conductors, Switchyard Bus, and High-Voltage Insulators

The AMR results for transmission conductors, switchyard bus, and high-voltage insulators are summarized in Attachment 1, Section 5.3, "Aging Management Review Results Table," of the June 26, 2002, letter from the applicant. The applicant stated that its AMR of McGuire and Catawba transmission conductors, switchyard bus, and high-voltage insulators followed the guidance provided in EPRI License Renewal Electrical Handbook and is consistent with the guidance provided in Chapter 8 of the License Renewal Electrical Handbook.

McGuire and Catawba transmission conductors, switchyard bus, and high-voltage isulators are designed and constructed like, and have the same materials as, the Oconee transmission conductors, switchyard bus, and high-voltage insulators with one notable difference. The difference is that multi-cone insulators (where several porcelain cone insulators are cemented together to form a post) used in post application were not included in the Oconee review. Other differences between the Oconee, McGuire, and Catawba transmission conductors, switchyard bus, and high-voltage insulators are not significant to the aging management review.

3.6.4.4.1 Aging Effects

Based on industry literature, plant operating experience, and the applicant's AMR for Oconee, potential aging effects for transmission conductors, switchyard bus, and high-voltage insulators were identified in Section 5.2, "Aging Management Review for Transmission Conductors, Switchyard Bus, and High-Voltage Insulators," of the supplemental information provided in Attachment 1 of the applicant's June 26, 2002, letter. The applicant's review accounted for industry operating experience reports for transmission conductors, switchyard bus, and high-voltage insulators identified in Chapter 11 of the License Renewal Electrical Handbook. The process for identifying aging effects was consistent with the process used in Section 3.6 of the Oconee LRA.

McGuire and Catawba transmission conductors, switchyard bus, and high-voltage insulators are installed in an external environment (bounding 105 °F, negligible radiation, and exposure to precipitation). The aging effects identified for transmission conductors, switchyard bus, and high-voltage insulators are not heat-related; therefore, ohmic heating is not included.

Loss of Conductor Strength for Transmission Conductors. The applicant stated that the transmission conductors included in the AMR are constructed of aluminum conductor steel reinforced (ACSR). The most prevalent mechanism contributing to loss of conductor strength of an ACSR transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR conductors, degradation begins as a loss of zinc from the galvanized steel core wires. Corrosion rates depend to a great extent on air quality, which includes suspended particles chemistry, SO2 concentration in air, precipitation, fog chemistry, and meteorological conditions. Duke has been installing and maintaining transmission conductors on its transmission system for more than 50 years and has not yet had to replace any conductors due to aging problems. There are no applicable aging effects that could cause loss of intended function of the transmission conductors for the period of extended operation.

Connection Surface Oxidation for Aluminum Switchyard Bus. The applicant stated that all bus connections within the component boundaries are welded connections. For the ambient environmental conditions at McGuire and Catawba, no aging effects have been identified that could cause a loss of intended function for the extended period of operation. Therefore, there are no applicable aging effects for the aluminum bus.

Surface Contamination Assessment for High-Voltage Insulators. The applicant stated that various airborne materials such as dust, salt, and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual and, in most areas, such contamination is washed away by rain. The glazed insulator surface aids this contamination removal. A large buildup of contamination enables the conductor to track along the surface more easily and can lead to insulator flashover. Surface contamination can be a problem in areas where there is a greater concentration of airborne particles such as near facilities that discharge soot or near the sea coast where salt spray is prevalent. McGuire and Catawba are located in an area with moderate rainfall where airborne particle concentrations are comparatively low. Consequently, the rate of contamination buildup on the insulators is not significant. At McGuire and Catawba, as in most areas of the Duke Power transmission system, contamination build up on insulators is not a problem. Therefore, surface contamination is not an applicable aging effect for the insulators in the service conditions they are exposed to at McGuire and Catawba.

Cracking Assessment for High-Voltage Insulators. The applicant stated that cracks have been known to occur with insulators when the cement that binds the parts together expands enough to crack the porcelain. This phenomenon, known as cement growth, occurs mainly because of improper manufacturing processes or materials, which make the cement more susceptible to moisture penetration, and the specific design and application of the insulator.

The string insulators susceptible to porcelain cracking caused by cement growth are isolated to bad batches (specific, known brands and manufacture dates) of string insulators used in strain application. The post insulators most susceptible to this aging effect are multi-cone (post) insulators used in cantilever applications. In the mid-1990s when this problem was identified, Duke undertook a program to identify and replace the most susceptible insulators system wide, including those in the McGuire and Catawba switchyards. Accordingly, cracking due to cement growth is not an applicable aging effect for the insulators currently installed in the McGuire and Catawba switchyards.

Loss of Material Due to Wear Assessment for High-Voltage Insulators. The applicant stated that mechanical wear is an aging effect for strain and suspension insulators in that they are subject to movement. Movement of the insulators can be caused by wind blowing the supported transmission conductor, causing it to swing from side to side. If this swing is frequent enough, it could cause wear in the metal contact points of the insulator string and between an insulator and the supporting hardware. Although this mechanism is possible, experience has shown that the transmission conductors do not normally swing and that when they do, because of substantial wind, they do not continue to swing for very long once the wind has subsided. Wear has not been identified during routine inspection. Loss of material due to wear will not cause a loss of intended function of the insulators at McGuire and Catawba. Therefore, loss of material due to wear is not an applicable aging effect for insulators.

3.6.4.4.2 Aging Management Programs

The applicant stated that, based upon its review of materials and service conditions, no applicable aging effects were identified. Therefore, McGuire and Catawba transmission conductors, switchyard bus, and high-voltage insulators will perform their intended functions in accordance with CLB during the period of extended operation, and no aging management is required.

3.6.4.5 Staff Evaluation of Aging Management Review Results for Transmission Conductor, Switchyard Bus, and High-Voltage Insulators

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 electrical components required for SBO at McGuire and Catawba. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on electrical components required for SBO will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.4.5.1 Aging Effects

McGuire and Catawba transmission conductors, switchyard bus, and high-voltage insulators are installed in an external environment (bounding 105 °F, negligible radiation, and exposure to precipitation). The aging effects identified for transmission conductors, switchyard bus, and high-voltage insulators are not heat-related so ohmic heating is not included.

The transmission conductors are constructed of ACSR. The most prevalent mechanism contributing to loss of conductor strength of an ACSR transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR conductors, degradation begins as a loss of zinc from the galvanized steel core wires. Corrosion rates depend to a great extent on air quality, which includes suspended particles chemistry, SO2 concentration in air, precipitation, fog chemistry, and meteorological conditions. Tests performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion. Corrosion of ACSR conductors is a very slow-acting aging effect, which is even slower in rural areas with generally fewer suspended particles and lower SO2 concentrations in the air than in urban areas. The applicant stated that it has been installing and maintaining transmission conductors on its transmission system for more than 50 years and has not yet had to replace any conductors due to aging problems. The staff finds that based on the test results, corrosion of ACSR conductors is a very slow-acting aging effect. Operating experience has also shown that corrosion of ACSR conductors is not a problem for transmission conductors at Duke's plants. Therefore, loss of material strength of ACSR transmission conductors does not require aging management for the period of extended operation.

All bus connections within the component boundaries are welded connections. For the ambient environment conditions at McGuire and Catawba, no aging effects have been identified that could cause a loss of intended function for the extended period of operation. Therefore, the staff concludes that there are no applicable aging effects for the switchyard bus.

Various airborne materials such as dust, salt, and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual, and in most areas such contamination is washed away by rain. The glazed insulator surface aids this contamination removal. A large buildup of contamination enables the conductor to track along the surface more easily and can lead to insulator flashover. Surface contamination can be a problem in areas where there is a greater concentration of airborne particles such as near facilities that discharge soot or near the sea coast where salt spray is prevalent. McGuire and Catawba are located in an area with moderate rainfall where airborne particle concentrations are comparatively low. Consequently, the rate of contamination buildup on the insulators is not significant. At McGuire and Catawba, as in most areas of the Duke Power transmission system, contamination buildup on insulators is not a problem. The staff finds that contamination buildup on the high-voltage insulators is not significant. Therefore, surface contamination is not an applicable aging effect for the insulators in the service conditions they are exposed to at McGuire and Catawba.

Cracks have been known to occur with insulators when the cement that binds the parts together expands enough to crack the porcelain. This phenomenon, known as cement growth, occurs mainly because of improper manufacturing process or materials, which make the cement more susceptible to moisture penetration, and the specific design and application of the insulator. The applicant stated that the string insulators susceptible to porcelain cracking caused by cement growth are isolated to bad batches (specific, known brands and manufacture dates) of string insulators used in strain application. The post insulators most susceptible to this aging effect are multi-cone (post) insulators used in cantilever applications. In the mid-1990s when this problem was identified, Duke undertook a program to identify and replace the most susceptible insulators system wide, including those in the McGuire and Catawba switchyards. The staff finds that porcelain cracking caused by cement growth is mainly due to improper manufacturing process or material. Accordingly, cracking due to cement growth is not an applicable aging effect for the insulators currently installed in the McGuire and Catawba switchyards.

Mechanical wear is an aging effect for strain and suspension insulators in that they are subject to movement. Movement of the insulators can be caused by wind blowing the supported transmission conductor, causing it to swing from side to side. If this swing is frequent enough, it could cause wear in the metal contact points of the insulator string and between an insulator and the supporting hardware. Although this mechanism is possible, experience has shown that the transmission conductors do not normally swing and that when they do, because of substantial wind, they do not continue to swing for very long once the wind has subsided. Wear has not been identified during routine inspection. Loss of material due to wear will not cause a loss of intended function of the insulators at McGuire and Catawba. The staff finds that loss of material due to mechanical wear is not an applicable aging effect because transmission conductors do not normally swing, and if they do, because of substantial wind, they do not continue to swing for very long once the wind has subsided. Therefore, loss of material due to wear is not an applicable aging effect for insulators.

3.6.4.5.2 Aging Management Programs

The staff concluded that since no aging effects are identified for transmission conductors, switchyard bus, and high-voltage insulators, no aging management program is required.

3.6.4.6 Conclusions

Based on the review of the information provided in a letter from the applicant dated June 26, 2002, the staff concludes that no AMP is required for transmission conductors, switchyard bus, and high-voltage insulators. The applicant has demonstrated that there is a reasonable assurance that transmission conductors, switchyard bus, and high-voltage insulators at McGuire and Catawba will continue to perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

4. TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

The applicant described its identification of time-limited aging analyses (TLAAs) in Section 4.0 of the McGuire and Catawba LRA. The staff reviewed this section of the LRA to determine if the applicant had identified the TLAAs and demonstrated that they meet one of the criteria required by 10 CFR 54.21(c)(1). The staff also reviewed the LRA to determine if plant-specific exemptions had been identified by the applicant.

4.1.1 Technical Information in the Application

In Section 4.1 of the LRA, the applicant described the requirements for the technical information to be reported in the LRA regarding TLAAs, as stated in 10 CFR 54.21(c). These include a list of TLAAs, as defined in 10 CFR 54.3, "Definitions," and, if applicable, a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 that are based on TLAAs. The applicant also described the following criteria used to identify TLAAs at both McGuire and Catawba as required by 10 CFR 54.3:

- involve systems, structures, and components within the scope of license renewal as delineated in 10 CFR 54.4(a)
- consider the effects of aging
- involve time-limited assumptions defined by the current operating term (for example, 40 years)
- were determined to be relevant by the applicant in making a safety determination
- involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in 10 CFR 54.4(b)
- are contained or incorporated by reference in the CLB

The applicant listed the following specific documents that were reviewed to identify potential TLAAs for both plants:

- Duke/NRC licensing correspondence
- NUREG-0422, as supplemented, SER for McGuire
- NUREG-0954, as supplemented, SER for Catawba
- UFSARs for both McGuire and Catawba
- ITS for both McGuire and Catawba
- Facility Operating Licenses for both McGuire and Catawba

The document set used for the search is contained in the Electronic Licensing Library (ELL). The ELL contains over 30,000 documents and consists of virtually all correspondence between Duke Energy (formerly Duke Power Company) and the NRC (and its predecessor the Atomic Energy Commission). The information developed from the review of plant-specific source documents was reviewed to determine which calculations and analyses meet all six criteria of 10 CFR 54.3. The analyses and calculations that meet all six criteria were identified as either McGuire-specific or Catawba-specific TLAAs.

As required by 10 CFR 54.21(c)(1), an evaluation of each TLAAs must be performed to demonstrate one of the following:

(1) the analyses remain valid for the period of extended operation
(2) the analyses have been projected to the end of the period of extended operation
(3) the effects of aging on the intended function(s) will be adequately managed for the period of extended operation

In Sections 4.2 through 4.7 of the LRA, the applicant provided TLAAs for the following:

- reactor vessel neutron embrittlement, including analyses for upper shelf energy, pressurized thermal shock, and pressure-temperature limits
- metal fatigue, including analyses of ASME Section III Class 1 component fatigue, fatigue evironmental effects, and ASME Section III Class 2 and 3 piping fatigue
- environmental qualification of electrical equipment
- containment liner plate, metal containments, and penetration fatigue analysis
- reactor coolant pump flywheel fatigue
- leak-before-break analysis
- depletion of nuclear service water pond volume due to runoff

4.1.2 Staff Evaluation

Pursuant to 10 CFR 54.21(c), an applicant for license renewal is required to provide a list of TLAAs as part of the application for the renewal of a license. The staff reviewed the TLAAs identified by the applicant and described in Sections 4.2 through 4.7 of the LRA to verify that they met the six criteria of 10 CFR 54.3. The staff also sought to determine if the applicant had demonstrated that the analyses remain valid for the period of extended operation, the analyses had been projected to the end of the period of extended operation, or the effects of aging on the intended functions will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1).

4.1.3 Conclusions

The staff reviewed the information provided in LRA Section 4.1 and concludes that the applicant has adequately identified the TLAAs as required by 10 CFR 54.21(c), and that no 10 CFR 50.12 exemptions have been granted on the basis of the TLAAs as defined in 10 CFR 54.3.

4.2 Reactor Vessel Neutron Embrittlement

The application includes three TLAAs for evaluation of the reactor vessel (RV) beltline materials, including (1) calculation of the end-of-extended-life Charpy upper shelf energy value (C_vUSE values) for each beltline material, (2) calculation of the end-of-extended-life reference temperature value (i.e., RT_{PTS} values) for each beltline material, and (3) a calculation of pressure-temperature (P-T) limits. Each analysis has been updated to consider 20 years of additional plant operation at power. The TLAAs take into account the effects of the additional extended-operating-period neutron irradiation on the previous calculated end-of-life C_vUSE, the

RT_{PTS}, and P-T limit values for the McGuire and Catawba reactor vessels, and conservatively base the evaluations through 54 EFPYs of power operation.

4.2.1 Upper Shelf Energy

Appendix G to 10 CFR Part 50 requires that reactor vessel beltline materials have C_vUSE values in the transverse direction for the base metal and along the weld for the weld material, according to the ASME Code, of no less than 75 ft-lb (102 J) initially, and must maintain C_vUSE values throughout the life of the vessel of no less than 50 ft-lb (68 J). However, C_vUSE values below these criteria may be acceptable if it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that the lower values of C_vUSE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code. Regulatory Guide 1.99, Rev. 2, "Radiation Embrittlement of Reactor Vessel Materials," provides an expanded discussion regarding the calculations of C_vUSE values and describes two methods for determining C_vUSE values for reactor vessel beltline materials, depending on whether a given reactor vessel beltline material is represented in the plant's reactor vessel material surveillance program (i.e., 10 CFR Part 50, Appendix H program).

4.2.1.1 Technical Information in the Application

Section 4.2.1 of the application addressed the requirement that RV beltline materials have a pre-irradiated C_vUSE of not less than 75 ft-lb (102 J) and maintain a C_vUSE of not less than 50 ft-lb (68 J) throughout the life of the vessel, unless it is demonstrated, in a manner approved by the Director of the Office of Nuclear Reactor Regulation, that lower values of C_vUSE will provide margins of safety against fracture that are equivalent to those required by Appendix G of Section XI of the ASME Code. The applicant stated that the C_vUSE value has been calculated through the period of extended operation using guidance from Regulatory Guide 1.99, Rev. 2, "Radiation Embrittlement of Reactor Pressure Vessel Materials." A value of 54 EFPYs was used as the end-of-life criterion for the RV. The application contains the information derived from the C_vUSE analysis. It includes a list of all beltline materials, the weight percent copper in the steel, the end-of-life fluence for the reactor vessel located one-quarter from the vessel's inside surface (i.e., 1/4T thickness of the vessel), and the initial and final C_vUSE values. The applicant concludes that the end-of-life C_vUSE results are above the screening criterion of 50 ft-lb (68 J). The applicant states that the calculations have been projected through the period of extended operation and shown to meet the requirements of 10 CFR 54.21(c)(1)(ii).

4.2.1.2 Staff Evaluation

The applicant summarized the end-of-extended operating period upper shelf energy analyses for the McGuire and Catawba reactor vessel beltline materials in Tables 4.2-1 through 4.2-4 of the LRA. Since all of the C_vUSE values are above the 50 ft-lb (68 J) screening criterion, the staff finds that, with respect to C_vUSE, the Duke RVs have sufficient margin to perform their intended function through the end of the period of extended operation.

By letter dated January 28, 2002, the staff requested, in RAI 4.2-1, the applicant to clarify that Tables 4.2-1 through 4.2-4 of the LRA include the results of the TLAAs for upper shelf energies of beltline nozzle plates/forging materials and nozzle weld materials in the McGuire and Catawba vessels.

In its response dated April 15, 2002, the applicant stated that TLAAs for upper shelf energy (USE) of the reactor vessel beltline shell and nozzle materials are addressed in Section 4.2.1 and Tables 4.2-1 through 4.2-4 of the LRA. During its review, the applicant projected that some of the nozzle region locations would have an estimated 54 EFPYs fluence greater than 10^{17} neutrons/cm^2. Therefore, in accordance with 10 CFR 50, Appendix H, the applicant performed an analysis of nozzle region locations and confirmed that they are not the most limiting materials with regard to radiation damage. This analysis is based on a review of the certified material test reports which determined bounding material values for the nozzle region materials. This analysis provides the basis for the responses to this RAI and is available for onsite inspection. All nozzle region materials have been evaluated and a bounding value of USE was calculated. Since none of these nozzle region locations are limiting, no changes to the reactor vessel capsule surveillance program are necessary for license renewal.

In its April 15, 2002, response to RAI 4.2-1, the applicant provided the requested information and noted that, during the preparation of the responses to this RAI, Duke identified errors in C_vUSE values for the bounding nozzle materials, as summarized in Tables 4.2-1 through 4.2-4 of the LRA. Therefore, the applicant performed revised C_vUSE value calculations for the bounding nozzle base-metal and weld materials and submitted the revised calculations in Table 4.2-1A, which was included in the applicant's response to RAI 4.2-1. Table 4.2-1A provides the updated C_vUSE values for the bounding nozzle region locations and supercedes the C_vUSE values for the nozzle region materials previously provided in Section 4.2.1 of the LRA. The applicant also provided the requested additional unirradiated C_vUSE values and alloying chemistry in Table 4.2-1C in its April 15, 2002, response to RAI 4.2-1.

The staff performed an independent calculation of the end-of-extended life C_vUSE values for the beltline shell and nozzle materials used to fabricate the McGuire and Catawba RVs. The staff confirmed that none of the beltline nozzle materials were represented in the applicant's reactor vessel material surveillance program (i.e., 10 CFR Part 50 Appendix H Program; refer to AMP B.3.26 for a description of this program). For those RV beltline materials that were not represented in the applicant's reactor vessel material surveillance program, the staff applied Regulatory Position 1.2 of Regulatory Guide 1.99, Revision 2, to estimate the percent loss of C_vUSE as a function of copper content and neutron fluence for the beltline materials, as evaluated using the 54 EFPYs end-of-extended life fluence. For RV materials represented in the applicant's reactor vessel material surveillance program, the staff applied Regulatory Position 2.2 as its basis for estimating the percentage drop in C_vUSE. The staff confirmed that all RV beltline shell and nozzle materials will continue to satisfy the C_vUSE value requirements of 10 CFR Part 50, Appendix G, through the end-of-extended operating lives for the McGuire and Catawba reactors units. Therefore, the staff concludes that the applicant's TLAA for calculating the USE values of the McGuire and Catawba RV beltline materials is acceptable because it meets the requirements of 10 CFR 54.21(c)(1)(ii) and will ensure that the RV materials will have adequate upper shelf energy levels and fracture toughness through the end-of-extended operating periods for the McGuire and Catawba reactor units.

By letter dated September 13, 2002, the staff requested additional information regarding the impact of the fracture toughness data from a Diablo Canyon 2 surveillance capsule (capsule V) on the USE assessments for the longitudinal RV beltline welds fabricated from heat No. 21935/12002 at the end of the extended operating term (or end of life extended, EOLE). For tracking purposes, this request was characterized by the staff as open item 4.2-1. The material is common to both the McGuire 1 and Diablo Canyon 2 RVs. For McGuire 1, the welds fabricated from this heat are the lower shell longitudinal welds under the plant-specific designation 3-442. This is the limiting McGuire 1 RV material for USE. In its response letter dated October 28, 2002, the applicant provided the following response to item 4.2-1, as it relates to the USE TLAA for McGuire 1 RV longitudinal welds fabricated from the weld heat No. 21925/12008, using all applicable surveillance data for the heat from the Diablo Canyon 2 RV material surveillance program (inclusive of fracture toughness tests performed on test specimens from Diablo Canyon 2 capsules U, X, Y, and V):

> To evaluate the impact of new data to the USE reported in Table 4.2-1 of the Application, Duke applied the chemistry data from the surveillance capsule report, WCAP-15423, concerning the same weld wires Heat 12008 and 21935 and Linde 1092 Flux Lot as McGuire Unit 1 Lower Shell Longitudinal Weld Seams 3-442A, B, C. The percent copper changed from 0.213 percent (as reported in the Application) to 0.219 percent (as reported in WCAP-15423). Using Figure 2 of RG 1.99, Rev. 2, the difference in USE is less than a 0.5 percent drop. Therefore, the EOL USE would conservatively be 1 ft-lb less than the values provided in Table 4.2-1 of the Application and still above the regulatory limit of 50 ft-lb.

To independently assess the applicant's response to open item 4.2-1 and revised USE evaluation for the McGuire 1 RV welds fabricated from heat No. 21935/12008, the staff incorporated the Diablo Canyon 2 capsule V data for the weld heat into the staff's "Reactor Vessel Integrity Database (RVID)." The staff recalculated the USE value for the lower shell longitudinal 3-442 welds using the limiting fluence for these welds at EOLE, as assessed for the 1/4T location of the RV (i.e., 1.63×10^{19} n/cm^2), and using all relevant Diablo Canyon 2 surveillance data for heat No. 21935/12008 (i.e., inclusive of the capsule V data). Based on these inputs, the staff recalculated the USE value for these welds to be 57 ft-lb at EOLE. The staff's revised USE value for these welds at EOLE is above 50 ft-lb screening criterion of the rule for ferritic materials in the irradiated condition and demonstrates that the McGuire 1 RV will comply with the USE screening criteria of 10 CFR Part 50, Appendix G, Section IV.A.1, through the expiration of the extended period of operation for McGuire 1. The staff therefore concludes that the applicant's TLAA for the USE evaluation of McGuire 1 is acceptable pursuant to 10 CFR 54.21(c)(1)(ii). This resolves open item 4.2-1 as it relates to the USE assessment for McGuire 1.

4.2.2 Pressurized Thermal Shock

Section 50.61 of 10 CFR provides the fracture toughness requirements protecting the reactor vessels of pressurized water reactors against the consequences of pressurized thermal shock (PTS). Licensees are required to perform an assessment of the reactor vessel materials' projected values of the PTS reference temperature, RT_{PTS}, through the end of their operating license. If approved for license renewal, this would include TLAAs for PTS up through the end-of-extended operating terms for the McGuire and Catawba units. Upon approval of its application for an extended period of operation for Catawba and McGuire, this period would be 54 EFPYs. The rule requires each licensee to calculate the end-of-life nil ductility temperature value (i.e., RT_{PTS} value) for each material located within the beltline of the reactor pressure vessel. The RT_{PTS} value for each beltline material is the sum of the unirradiated nil ductility reference temperature (RT_{NDT}) value, a shift in the RT_{NDT} value caused by exposure to high energy neutron irradiation of the material (i.e., ΔRT_{NDT} value), and an additional margin value to account for uncertainties (i.e., M value). 10 CFR 50.61 also provides screening criteria against which the calculated RT_{PTS} values are to be evaluated. For reactor vessel beltline base-metal materials (forging or plate materials) and longitudinal (axial) weld materials, the materials are considered to provide adequate protection against PTS events if the calculated RT_{PTS} values are less than or equal to 270 °F; for reactor vessel beltline circumferential weld materials, the materials are considered to provide adequate protection against PTS events if the calculated RT_{PTS} values are less than or equal to 300 °F. Regulatory Guide 1.99, Rev. 2, "Radiation Embrittlement of Reactor Vessel Materials," provides an expanded discussion regarding the calculations of RT_{PTS} values and describes two methods for determining RT_{PTS} for reactor vessel materials, depending on whether a given reactor vessel beltline material is represented in the plants reactor vessel material surveillance program (i.e., 10 CFR Part 50, Appendix H program).

4.2.2.1 Technical Information in the Application

Section 4.2.2 of the LRA addresses the 10 CFR 50.61 requirement that the RV be protected against pressurized thermal shock. The applicant states that the screening criteria in 10 CFR 50.61 are 270 °F for plates, forgings, and axial welds, and 300 °F for circumferential welds. According to the regulation, if the calculated RT_{PTS} values for the beltline materials are less than the screening criteria, then the RV is acceptable with respect to risk of failure during postulated thermal shock transients. In this part of the application, the applicant describes the projected values of RT_{PTS} over the period of extended operation (54 EFPY) to demonstrate that the screening criteria are not violated. The applicant states that this analysis has been carried out and that the results do not exceed the screening criteria. The applicant states that the calculations have been projected through the period of extended operation and shown to meet the requirements of 10 CFR 54.21(c)(1)(ii).

4.2.2.2 Staff Evaluation

The applicant provided its end-of-extended operating PTS assessments for the McGuire and Catawba beltline reactor vessel shell materials in Tables 4.2-5 through 4.2-8 of the LRA, but did not include the PTS assessments of the beltline nozzle and weld materials. By letter dated January 28, 2002, the staff requested, in RAI 4.2-1, the following information regarding the end-of-extended operating period PTS assessments for the McGuire and Catawba beltline reactor vessel shell and nozzle materials:

(1) The corresponding pressurized thermal shock time-limited aging analysis (TLAA) assessments for the nozzle plate/forging materials and nozzle weld materials that were analyzed for upper shelf energy adequacy (as provided for in Tables 4.2-1 through 4.2-4 of the LRA)

(2) The unirradiated Charpy impact data, unirradiated initial RT_{NDT} data (i.e., $RT_{NDT(U)}$ data) and alloying chemistry data (especially copper and nickel contents, as well as phosphorous and sulfur contents) for the beltline nozzle plates/forging materials and nozzle weld materials in the McGuire and Catawba vessels on the respective dockets for the McGuire and Catawba reactor units (i.e., Dockets Nos. 50-369, 50-370, 50-413 and 50-414), and the bases for the data being docketed

In its response to RAI 4.2-1, dated April 15, 2002, the applicant provided the following additional information and data regarding end-of-extended operating period PTS assessments for the McGuire and Catawba beltline reactor vessel shell and nozzle materials:

- Table 4.2-1B, providing revised PTS assessments for the bounding beltline nozzle base metal and weld materials for the McGuire and Catawba reactor vessels
- Table 4.2-1C, providing selected unirradiated upper shelf energy, unirradiated RT_{NDT}, and alloying chemistry data for the bounding beltline nozzle base metal and weld materials for the McGuire and Catawba reactor vessels

The staff performed an independent calculation of the RT_{PTS} values for the McGuire and Catawba beltline reactor vessel shell and nozzle materials, as assessed, based on the projected end-of-extended operating term (54 EFPY) neutron fluences for the materials. In reviewing the applicant's description of the PTS analysis, the staff examined the data and results of the analysis, as summarized in Tables 4.2-5 through 4.2-8 of the LRA and in Tables 4.2-1B and 4.2-1C of the applicant's response to RAI 4.2-1. Although the staff's calculated RT_{PTS} values for the RV beltline shell and nozzle materials were not always consistent with the applicant's calculated RT_{PTS} values, both the staff's and the applicant's PTS analyses confirm that the RT_{PTS} values for the McGuire and Catawba beltline materials will remain under the PTS screening criteria of 10 CFR 50.61 through the end-of-the-extended-operating periods for the units. For the McGuire 1 RV, the staff determined that the lower shell plate longitudinal welds 3-442 A and C are the most limiting materials and calculated the end-of-extended operating term RT_{PTS} value for these materials to be 248 °F. For the McGuire 2 RV, the staff determined that lower shell forging 04 is the most limiting material and calculated the end-of-extended operating term RT_{PTS} value for this material to be 152 °F. For the Catawba 1 RV, the staff determined that lower shell forging 04 is the most limiting material and calculated the end-of-extended operating term RT_{PTS} value for this material to be 62 °F. For the Catawba 2 RV, the staff determined that intermediate shell plate B8605-2 is the most limiting material and calculated the end-of-extended operating term neutron fluence for this material to be 133 °F. All of these materials meet the 10 CFR 50.61 screening criteria for longitudinal weld and base metal materials of 270 °F. Based on these considerations, the staff finds the applicant's TLAAs for protecting the McGuire and Catawba vessels against PTS to be acceptable because the staff confirmed that the RT_{PTS} values for all McGuire and Catawba reactor vessel beltline shell and nozzle materials remain below the screening criteria of 10 CFR 50.61. The staff therefore concludes that the applicant's TLAA for calculating the RT_{PTS} values for the McGuire and Catawba RV beltline materials is acceptable because it meets the requirements of 10 CFR 54.21(c)(1)(ii) and will ensure that the RV materials will have sufficient protection against PTS events through the end-of-extended operating periods for the McGuire and Catawba reactor units.

By letter dated September 13, 2002, the staff requested additional information regarding the impact of the fracture toughness data from the Diablo Canyon 2 surveillance capsule on the PTS assessments for the longitudinal RV beltline welds fabricated from heat No. 21935/12002 at the end of the extended operating term (or end of life extended or EOLE). For tracking purposes, this request was characterized by the staff as open item 4.2-1. The material is common to both the McGuire 1 and Diablo Canyon 2 RVs. For McGuire 1, the welds fabricated from this heat are the lower shell longitudinal welds under the plant-specific designation 3-442. This is the limiting McGuire 1 RV material for PTS.

In its response to open item 4.2-1, dated October 28, 2002, the applicant provided a revised PTS evaluation for these welds. Using a limiting fluence of 2.73×10^{19} n/cm^2 at EOLE, the applicant's revised PTS assessment projected the RT_{PTS} values for these welds to be 253 °F using all relevant surveillance capsule data for the heat No. 21935/12008, as obtained from docketed information from the Diablo Canyon 2 RV material surveillance program (inclusive of fracture toughness tests performed on test specimens from Diablo 2 capsules U, X, Y, and V). This RT_{PTS} value at EOLE meets the screening criterion for longitudinal welds as stated in the PTS rule (i.e., the value is less than 270 °F) and is, therefore, acceptable.

To independently assess the applicant's response to open item 4.2-1 and revised PTS evaluation for the McGuire 1 RV welds fabricated from heat No. 21935/12008, the staff incorporated the Diablo Canyon 2 capsule V data for the weld heat into the staff's "Reactor Vessel Integrity Database (RVID)." The staff recalculated the RT_{PTS} value for the lower shell longitudinal 3-442 welds using the limiting fluence for these welds at EOLE (i.e., 2.73×10^{19} n/cm^2) at the inner surface of the RV, and using all relevant Diablo Canyon 2 surveillance data for heat No. 21935/12008 (i.e., inclusive of the Capsule V data). The staff recalculated the RT_{PTS} value for these welds to be 260 °F at EOLE. The staff's revised RT_{PTS} value for these welds at EOLE meets the screening criterion for longitudinal welds as stated in the PTS rule and demonstrates that the McGuire 1 RV will comply with the fracture toughness and PTS criteria of 10 CFR 50.61 through the end of the extended period of operation for McGuire 1. The staff therefore concludes that the applicant's TLAA for the PTS evaluation of McGuire 1 is acceptable pursuant to 10 CFR 54.21(c)(1)(ii). This resolves open item 4.2-1 as it relates to the PTS assessment for McGuire 1.

4.2.3 P-T Limits

The requirements in 10 CFR Part 50, Appendix G, are designed to protect the integrity of the reactor coolant pressure boundary in nuclear power plants. The staff evaluates the pressure-temperature (P-T) limit curves based on NRC regulations and guidance. Appendix G to 10 CFR Part 50 requires that P-T limit curves be at least as conservative as those obtained by applying the methodology of Appendix G to Section XI of the ASME Boiler and Pressure Vessel Code. Appendix G to
10 CFR Part 50 also provides minimum temperature requirements that must be considered in the development of the P-T limit curves. SRP Section 5.3.2 provides an acceptable method of determining the P-T limit curves for ferritic materials in the beltline of the RPV based on the linear elastic fracture mechanics (LEFM) methodology of Appendix G to Section XI of the ASME Code. The critical locations in the RPV beltline region for calculating heatup and cooldown P-T curves are the 1/4 thickness (1/4T) and 3/4 thickness (3/4T) locations, which correspond to the maximum depth of the postulated inside surface and outside surface defects, respectively.

Operation of the RCS is also limited by the net positive suction curves for the reactor coolant pumps. These curves specify the minimum pressure required to operate the reactor coolant pumps. Therefore, in order to heat up and cool down, the reactor coolant temperature and pressure must be maintained within an operating window established between the Appendix G P-T limits and the net positive suction curves of the reactor coolant pumps.

4.2.3.1 Technical Information in the Application

In Section 4.2.3 of the LRA, the applicant addresses the requirement in 10 CFR Part 50, Appendix G, that normal operations, including heatup, cooldown, and transient operating conditions, and pressure-test operations of the RV be accomplished within established P-T limits. These limits are established by calculations that utilize the materials and fluence data obtained through the unit specific reactor surveillance capsule program.

4.2.3.2 Staff Evaluation

The P-T limits are established by calculations that utilize the materials and fluence data obtained through the unit-specific reactor surveillance capsule program.

Normally, the P-T limits are calculated for several years into the future and remain valid for an established period of time not to exceed the current operating license expiration. The current P-T limit curves for the McGuire units are acceptable through 16 EFPYs of power operation; the current P-T limit curves for the Catawba units are acceptable though 15 EFPYs of power operation. Section 50.90 of 10 CFR requires licensees to submit new P-T limit curves for operating reactors for review and have the curves approved and implemented into the Technical Specifications for the reactor units prior to the expiration of the most current P-T limit curves approved in the Technical Specifications. The applicant will be required to submit the extended-period-of-operation P-T limit curves for the McGuire and Catawba RVs and have the curves approved against the criteria of 10 CFR Part 50, Appendix G, and implemented into the Technical Specifications prior to operation of the reactors during the extended operating terms for the units.

The issue raised in open item 4.2-1 on the McGuire 1 TLAAs for neutron irradiation embrittlement (i.e., the McGuire 1 TLAAs for PTS, USE, and P-T limits), as stated in the staff's letter of September 9, 2002, does not change the staff's conclusion that the applicant is required to submit P-T limit curves for the period of extended operation before it begins operation beyond the first 40 years. However, since the P-T limits for McGuire 1 are based on the RT_{NDT} value for the RV lower shell longitudinal welds fabricated from material heat No. 21935/12008, any P-T curves for McGuire 1 for the extended period of operation, when submitted to the staff for review and approval, will need to account for all relevant surveillance capsule data for this heat as obtained from the Diablo Canyon 2 RV material surveillance program. The staff will evaluate the extended-period-of-operation P-T limit curves for the McGuire and Catawba RVs prior to expiration of the 40-year, current-operating-term P-T limit curves for the units. The staff's review of the extended-period-of-operation P-T limit curves, when submitted, will ensure that the operations of the RCS for the McGuire and Catawba units will be done in a manner that ensures the integrity of the RCS during the extended periods of operation for the McGuire and Catawba units as required by 10 CFR 54.21(c)(1)(ii).

4.2.4 FSAR Supplement

On the basis of the staff's evaluation described above, the summary description for the RCS TLAAs described in the FSAR Supplement (LRA, Appendix A) are acceptable.

4.2.5 Conclusions

The staff has reviewed the TLAAs regarding the maintenance of acceptable Charpy USE levels for the McGuire and Catawba RV materials and the ability of the McGuire and Catawba reactor vessels to resist failure during postulated PTS events. On the basis of this evaluation, the staff concludes that the applicant's TLAAs for Charpy USE and PTS meet the respective requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.61 for the McGuire and Catawba

RV beltline materials as evaluated to the end-of-extended-operating periods for the McGuire and Catawba units, and therefore satisfy the requirements of 10 CFR 54.21(c)(1)(ii) for 60 years of operation. The staff will evaluate the end-of-extended-operating term P-T limit curves for the McGuire and Catawba reactor units upon submittal by the applicant. The staff's review of the extended-period-of-operation P-T limit curves, when submitted, will ensure that the operations of the RCS for the McGuire and Catawba units will be done in a manner that ensures the integrity of the RCS during the extended periods of operation for the McGuire and Catawba units and that the curves, when submitted, will satisfy the requirements of 10 CFR 54.21(c)(1)(ii) for the period of extended operation.

4.3 Metal Fatigue

A metal component subjected to cyclic loads may fail at a load magnitude less than its ultimate load capacity due to metal fatigue, initiating and propagating cracks in the material. The fatigue life of a component is a function of its material, its environment, and the number and magnitude of the applied cyclic loads. Fatigue was a design consideration for plant mechanical components in the McGuire and Catawba facilities and, consequently, fatigue is part of the current licensing basis for these components. The applicant addressed the TLAA evaluations performed to address thermal fatigue analyses of plant mechanical components in Section 4.3 of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has evaluated the TLAA in accordance with the requirements of 10 CFR 54.21(c)(1).

4.3.1 Technical Information in the Application

The applicant discussed the evaluation of ASME Section III, Class 1 components in Section 4.3.1 of the LRA. The applicant indicated that the Thermal Fatigue Management Program (TFMP) will be used to manage thermal fatigue of these components during the period of extended operation for both McGuire and Catawba. The elements of the TFMP are described in Section 4.3.1.1 of the LRA. The applicant indicated that the scope of the program includes the following components:

- RCS Class 1 components (including piping connected to the RCS falling under the purview of NRC Bulletins 88-08 and 88-11)
- the replacement steam generators (RSG) Class 1 portion and selected non-Class 1 portions of the RSG
- components falling within the ISI Program that contain flaws that exceed acceptance standards, but were shown to be acceptable using fracture analyses techniques that used an assumed set of thermal transient cycles
- four Catawba non-Class 1 heat exchangers designed based on RCS thermal cycle transient limits

The applicant described the actions taken to address the issue of environmentally assisted fatigue in Section 4.3.1.2 of the LRA for both McGuire and Catawba. The applicant indicated that it will use Method 2 contained in draft EPRI report, "Guidelines for Addressing Fatigue Environmental Effects in a License Renewal Application (MRP-47)," to perform the evaluation. The applicant also indicated that the evaluation will address the fatigue sensitive component locations identified in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components."

The applicant described the evaluation of ASME Section III, Class 2 and 3 piping in Section 4.3.2 of the LRA for both McGuire and Catawba. The applicant also indicated that a number of systems designed to the requirements of ANSI B31.1 are in the scope of license renewal. The applicant concluded that the Class 2 and 3 piping analyses of these systems remain valid for 60 years of operation.

4.3.2 Staff Evaluation

Components of the RCS at both McGuire and Catawba were designed to the Class 1 requirements of the ASME Code. The Class 1 requirements contain explicit criteria for the fatigue analysis of components. Consequently, the applicant identified the fatigue analysis of these components as TLAAs. The staff reviewed the applicant's evaluation of the ASME Class 1 RCS components for compliance with the provisions of 10 CFR 54.21(c)(1).

The specific design criterion for ASME Class 1 components involves calculating the CUF. The fatigue damage in the component caused by each thermal or pressure transient depends on the magnitude of the stresses caused by the transient. The CUF sums the fatigue damage resulting from each transient. The design criterion requires that the CUF not exceed 1.0.

The applicant relies on the TFMP to manage the thermal fatigue design basis of Class 1 components during the period of extended operation. Tables 5-2 and 5-49 of the McGuire UFSAR and Table 3-50 of the Catawba UFSAR contain a list of transient design conditions and associated design cycles used for the design of Class 1 components. By letter dated January 28, 2002, the staff requested, in RAI 4.3-1, that the applicant provide the following data:

- the current number of operating cycles and a description of the method used to determine the number and severity of the design transients from the plant operating history
- the number of operating cycles estimated for 60 years of plant operation and a description of the method used to estimate the number of cycles at 60 years

In its response dated April 15, 2002, the applicant indicated that plant operating conditions are continually monitored for plant conditions that meet the definition of a transient monitored by the TFMP. The applicant further indicated that the parameters associated with the number and severity of these transients is entered into a database. The applicant provided the current number of cycles for each transient at each unit in Table 4.3-1 of its response. The applicant's response indicated that the projected number of transients would not exceed the number assumed in the design for a 60-year operating period. The applicant also identified new transients associated with the McGuire replacement steam generators that will be added to the TFMP. These new transients are also identified in Table 4.3-1 of its response.

Although the projections are for a 60-year operating period, thermal fatigue of Class 1 piping and components is monitored by the TFMP and not an analytical demonstration pursuant to 10 CFR 54.21(c)(1)(i) or 10 CFR 54.21(c)(1)(ii). Therefore, the staff's evaluation of the applicant's TLAA for monitoring thermal fatigue of Class 1 piping and components is for the period of extended operation, not a 60-year operating period.

The applicant also identified the design transients listed in Tables 5-2 and 5-49 of the of the McGuire UFSAR and Table 3-50 of the Catawba UFSAR that are not tracked by the TFMP.

The applicant indicated that the estimated design cycles associated with loading and unloading at 5 percent of full power were based on the assumption of load-follow operation, whereas the plant is operated in the base-load mode. The staff agrees that the number of design cycles listed in the UFSAR tables for these transients are conservative, based on the information presented in NUREG/CR-6260 for Westinghouse plants. The applicant also indicated that the step load increase and decrease of 10 percent of full power causes insignificant fatigue and is not counted. This transient was not identified as a major contributor to fatigue usage for Westinghouse plants in NUREG/CR-6260. The staff notes that, although this transient is monitored at the Turkey Point, Surry, and North Anna facilities, the responses to staff RAIs regarding the LRAs for these facilities indicates that the number of these design transients is expected to be far less than design number for the period of extended operation. On the basis of monitoring at other facilities and the information presented in NUREG/CR-6260, the staff finds the applicant's statement, that this transient causes insignificant fatigue, a reasonable justification for why the step load increase and decrease of 10 percent of full power is not counted in the TFMP.

The Catawba UFSAR lists a large number of design cycles for charging and letdown flow changes. The applicant's response indicates that these transients cause insignificant fatigue and are not counted. NUREG/CR-6260 contains a discussion of these transients for the newer vintage Westinghouse plant. The discussion indicates that these transients are not normally counted at PWRs, although some PWRs have reported that the actual cycles of these transients are less than the numbers assumed in the design calculations. However, the NUREG/CR-6260 evaluation indicates the fatigue usage at the charging nozzle for these transients is significant when the reactor water environment is considered. The charging nozzle is one of the locations that the applicant will assess for fatigue environmental effects. The assessment for fatigue environmental effects is discussed later in this section of this SER.

The Westinghouse Owners Group (WOG) issued Topical Report WCAP-14575-A, "Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components," to address aging management of the RCS piping. Renewal applicant action item 8 of the accompanying staff SE requests that a license renewal applicant perform an additional fatigue evaluation or propose an AMP to address components labeled I-M and I-RA in Tables 3-2 through 3-16 of WCAP-14575. By letter dated January 28, 2002, the staff requested, in RAI 4.3-3, that the applicant discuss how the TFMP addresses the components labeled I-M and I-RA in Tables 3-2 through 3-16 of WCAP1475-A. In its response dated April 15, 2002, the applicant indicated that WCAP-14575-A had not been considered in the LRA. However, the applicant indicated that it had reviewed WCAP-14575-A in order to respond to the RAI. The applicant indicated that the TFMP manages the thermal fatigue design basis for the components identified in WCAP-14575-A. The applicant's TFMP requires corrective actions to be initiated if the number of cycles exceeds the number assumed in the design. The staff concludes that the components identified in WCAP-14575-A will be adequately addressed by the applicant's TFMP.

The WOG issued the generic Topical Report WCAP-14574-A, "License Renewal Evaluation: Aging Management Evaluation for Pressurizers," to address aging management of pressurizers. Renewal applicant action item 1 of the accompanying staff SE requests that a license renewal applicant demonstrate that the pressurizer sub-component CUFs remain below 1.0 for the period of extended operation. Table 2-10 of WCAP 14574-A indicates that the ASME Section III Class 1 fatigue CUF criterion could be exceeded at several pressurizer sub-component locations during the period of extended operation. WCAP-14574-A also identified recent unanticipated transients that were not considered in the original ASME Section III Class 1 fatigue analyses. By letter dated January 28, 2002, the staff requested, in RAI 4.3-4, that the applicant provide the following information:

- an evaluation to confirm that the additional transients discussed in WCAP-14574-A, not considered in the original design, have been addressed at McGuire and Catawba
- a list of the ASME Section III Class 1 CLB CUFs for the applicable sub-components of the McGuire and Catawba pressurizers specified in Table 2-10 of WCAP-14574-A and the corresponding CUFs for the extended period of operation
- a discussion of the impact of the environmental fatigue correlations provided in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," on the above results

In its response dated April 15, 2002, the applicant indicated that WCAP-14574-A had not been considered in the LRA. However, the applicant indicated that it had reviewed WCAP-14574-A in order to respond to the RAI. Regarding the first issue, the applicant indicated that modified operating procedures had been implemented at McGuire and Catawba to mitigate the effects of insurge/outsurge. In addition, historical plant instrument data were analyzed to determine the insurge/outsurge history both before and after modification of the operating procedures. The applicant indicated that an analysis including these events found that the design CUFs of all components will remain less than 1.0. By letter dated July 9, 2002, the applicant provided the CUFs for the sub-components listed in Table 2-10 of WCAP-14574-A, but did not discuss the impact of the environmental fatigue correlations on these sub-components. Pending completion of the staff's review of the information provided and assessment of the impact of the environmental correlations for these sub-components, this issue was characterized as SER open item 4.3-1.

In its letter dated July 9, 2002, the applicant identified several pressurizer sub-components with relatively high design CUFs for McGuire and Catawba. These sub-components include the shell, spray nozzle, lower head heater penetration and nozzle weld, instrument nozzle, and surge nozzle. An assessment by the staff applying a conservative estimate of the environmental factor to these locations indicates that the CUFs may exceed 1.0 during the period of extended operation. Similar results were obtained by previous license renewal applicants with Westinghouse NSSS designs. A discussion of these assessments is contained in the staff SERs related to the license renewal of the Turkey Point and North Anna/Surry facilities.

The Turkey Point and North Anna/Surry license renewal applicants used a combination of quantitative and qualitative assessments to argue that the actual CUFs, including environmental effects, are not expected to exceed 1.0 during the period of extended operation. If similar quantitative and qualitative assessments were performed for McGuire and Catawba, the staff would expect similar results to be obtained because McGuire and Catawba are Westinghouse NSSS designs, like Turkey Point, North Anna and Surry. These applicants also committed to monitor the fatigue usage, including environmental effects, of the surge line nozzle during the period of extended operation. The staff concluded that the surge line nozzle is an acceptable sample component to represent environmental effects on the pressurizer sub-components during the period of extended operation.

As discussed later in this SER, the applicant has committed to perform further evaluation of the surge line nozzle during the period of extended operation. The staff concludes that the applicant can use the surge line nozzle evaluation as a representative sample to address environmental effects on pressurizer sub-components for McGuire and Catawba during the period of extended operation. If the further evaluation of the surge line identifies the need for additional actions during the period of extended operation, then the applicant should demonstrate the acceptability of pressurizer sub-components, considering environmental fatigue effects, as part of its corrective action. On the basis of the staff's review documented above, open item 4.3-1 is closed.

The WOG has issued the generic Topical Report WCAP-14577, Revision 1-A, "License Renewal Evaluation: Aging Management for Reactor Internals," to address aging management of the reactor vessel internals. Renewal applicant action item 11 of the accompanying staff SE indicates that the fatigue TLAA of the reactor vessel internals should be addressed on a plant-specific basis. In the LRA, the applicant indicates that the TFMP will assure that component fatigue analyses will remain within their design values for the period of extended operation. By letter dated January 28, 2002, the staff requested, in RAI 4.3-2, that the applicant list the transients that contribute to the fatigue usage for each component listed in Table 3-3 of WCAP-14577, Revision 1-A, and discuss how the TFMP monitors these transients.

In its response dated April 15, 2002, the applicant indicated that WCAP-14577, Revision 1-A had not been considered in the LRA. The applicant stated that no TLAAs were identified for the McGuire or Catawba reactor internals, and that the reactor vessel internals were designed to ASME Section III, Class 2 criteria, which specified no time- or cycle-dependent requirements for the internals. The applicant did indicate that the rod cluster guide tube pins at McGuire and Catawba were replaced, and the replacement pins were analyzed for fatigue considering a 60-year design life. The applicant further indicated that the transients that contribute to the fatigue usage are included in the TFMP. The staff considers the applicant's response acceptable.

The applicant's TFMP tracks transients and cycles of RCS components that have explicit design transient cycles to assure that these components stay within their design basis. Generic Safety Issue (GSI)-166, "Adequacy of the Fatigue Life of Metal Components," raised concerns regarding the conservatism of the fatigue curves used in the design of the RCS components. Although GSI-166 was resolved for the current 40-year design life of operating components, the staff identified GSI-190, "Fatigue Evaluation of Metal Components for 60-year Plant Life," to address license renewal. The NRC closed GSI-190 in December 1999, concluding the following:

> The results of the probabilistic analyses, along with the sensitivity studies performed, the iterations with industry (NEI and EPRI), and the different approaches available to the licensees to manage the effects of aging, lead to the conclusion that no generic regulatory action is required, and that GSI-190 is closed. This conclusion is based primarily on the negligible calculated increases in core damage frequency in going from 40 to 60 year lives. However, the calculations supporting resolution of this issue, which included consideration of environmental effects, and the nature of age-related degradation indicate the potential for an increase in the frequency of pipe breaks as plants continue to operate. Thus, the staff concludes that, consistent with existing requirements in

> 10 CFR 54.21, licensees should address the effects of coolant environment on component fatigue life as aging management programs are formulated in support of license renewal.

Section 4.3.1.2 of the LRA discusses the applicant's evaluation of the impact of the reactor water environment on the fatigue life of components. The discussion indicates that the applicant's evaluation will use method 2 contained in draft EPRI Report MRP-47. The applicant provided a discussion of its proposed implementation of the EPRI Report MRP-47 guidelines. The applicant's proposed evaluation will include a sample of 6 to 10 locations selected for assessment. Locations for consideration will include the NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," locations and other locations expected to have high usage factors when considering environmentally assisted fatigue (EAF).

The staff is currently reviewing EPRI Report MRP-47 and has not yet endorsed the guidelines presented in the report. Consequently, by letter dated January 28, 2002, the staff requested, in RAI 4.3-5, that the applicant provide additional information regarding the evaluation of reactor water environmental effects. Specifically, the staff requested the following:

- confirmation that the environmental fatigue correlations contained in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue on Fatigue Design Curves of Austenitic Stainless Steels," will be used in the evaluation

- design basis usage factors for each of the six component locations listed in NUREG/CR-6260

- detailed technical evaluation which demonstrates that the proposed inspections provide an adequate basis for detecting fatigue cracking before such cracking leads to through wall cracking or pipe failure [The detailed technical evaluation was required to be sufficiently conservative to address all uncertainties associated with the technical evaluation (e.g., fatigue crack initiation and detection, fatigue crack size, and fatigue crack growth rate considering environmental factors). As an alternate to the detailed technical evaluation, a commitment was needed to monitor the fatigue usage, including environmental effects, during the period of extended operation, and to take corrective actions, as approved by the staff, if the usage was projected to exceed 1.0. The detailed technical evaluation was required because the applicant had indicated that ASME Section XI flaw evaluation and inspection procedures could be used as an alternate method to manage environmental fatigue. The NRC staff indicated that it has not endorsed a procedure on a generic basis which allows for ASME Section XI inspections in lieu of meeting the fatigue usage criteria.]

- additional data and evaluations which demonstrate that (1) there is sufficient margin in the procedure to account for material variability and experimental data scatter, size effects, surface finish effects, and loading history, and (2) environmental effects and surface effects are not independent effects. [As an alternative, the applicant's procedure should be revised to eliminate the Z factor. This information was needed because the applicant's procedure indicated that the environmental factor would be adjusted by a Z factor to take credit for moderate environmental effects in the existing ASME fatigue curves. The staff considers the use of the Z factor an open issue regarding implementation of the EPRI procedure.]

In its response dated April 15, 2002, the applicant confirmed that the environmental fatigue correlations in NUREG/CR-6583 and NUREG/CR-5704 will be used in the evaluations. Although the applicant indicated that NUREG/CR-6260 locations applicable to McGuire and Catawba correspond to those identified for a newer Westinghouse plant, the applicant did not provide the design usage factors for these locations in its RAI response. However, the applicant did provide, in subsequent electronic correspondence dated May 23, 2002 (ADAMS Accession No. ML023290427), a table of CUFs for newer-vintage Westinghouse plant locations identified in NUREG/CR-6260. This table was attached as an enclosure to a June 4, 2002, conference call summary, summarized by memorandum dated June 19, 2002. By letter dated July 9, 2002, the applicant provided these data in official correspondence. Additionally, the staff requested that the applicant provide design stresses and fatigue usage factors associated with the Catawba charging system flow changes discussed previously in this SER. Pending the staff's receipt of information pertaining to the Catawba charging flow changes and completion of the staff's review of the environmental impact on the fatigue usage for plant locations identified in NUREG/CR-6260, this issue was characterized as SER open item 4.3-2.

In its response to this SER open item, dated October 2, 2002, the applicant discussed the Catawba charging system flow transients. The applicant indicated that a review of the existing engineering calculations found that the charging and letdown flow change transients cause insignificant fatigue usage. The staff also had reviewed the engineering calculations during a September 18, 2002, meeting with the applicant (summarized by memorandum dated November 18, 2002) and confirmed that the Catawba charging flow transients were determined to cause insignificant fatigue usage. On the basis of the staff review of the applicant's engineering calculations for the Catawba charging system, this part of open item 4.3-2 is closed.

In its July, 9, 2002, submittal, the applicant identified relatively high design basis fatigue usage factors for the RPV outlet nozzle, surge line hot leg nozzle, charging nozzle, and safety injection nozzle for McGuire and Catawba. An assessment by the staff, applying a conservative estimate of the environmental factor to these locations, indicates that the CUFs of these components may exceed 1.0 during the period of extended operation. The applicant has committed to perform further evaluations of these components, considering environmental effects, prior to the period of extended operation in response to SER open item 4.3-4. This commitment is included in the revised FSAR supplements for Catawba and McGuire submitted by the applicant in a letter dated October 2, 2002. On the basis of the applicant's commitment to perform further evaluations of impact of the environment on the fatigue usage of these components, this part of open item 4.3-2 is closed.

The applicant agreed not to use the flaw tolerance/inspection procedures specified in Note 1 unless such procedures have been accepted by the NRC. In addition, the applicant agreed to revise the procedure specified in LRA Section 4.3.1.2 to set Z equal to 1.0. The staff finds these commitments acceptable.

In LRA Section 4.3.2, "ASME Section III, Class 2 and 3 Piping Fatigue," the applicant indicated that, for license renewal, all thermal cycle count assumptions for the non-Class 1 mechanical systems were conservatively re-validated for 60 years of operation. ASME Section III, pertaining to Class 2 and 3 piping design criteria, requires that a reduction factor be applied to the allowable bending stress range if the number of full range thermal cycles exceeds 7000. ANSI B31.1 contains the same requirement. The applicant indicated that two locations at

McGuire and Catawba could reach the 7000-cycle limit during the period of extended operation. By letter dated January 28, 2002, the staff requested, in RAI 4.3-7, that the applicant identify these locations and indicate how the number of expected cycles was determined. The staff also requested that the applicant describe the re-evaluation that was performed to demonstrate that these locations will be acceptable for the period of extended operation.

In its response dated April 15, 2002, the applicant stated that the number of expected thermal cycles of ASME III, Class 2 and 3 piping was determined by a conservative operational review to identify susceptible locations. The applicant stated that it had performed a comparison of actual operating experience to the design thermal cycle assumptions, including a projection of assumed future cycles, to determine the number of expected thermal cycles for 60 years of operation. The applicant indicated that the starting air compressor discharge piping in the diesel generator starting air system at McGuire and Catawba is expected to exceed 7000 cycles during the period of extended operation because of the frequent cycling of the air compressor. The applicant's response indicated that a portion of the drain piping in the main steam system at McGuire was projected to exceed 7000 cycles during the period of extended operation due to significant thermal cycling during startup. In addition, the pressurizer liquid sample piping at Catawba was frequently used to sample boron. The applicant indicated that the stresses in these piping systems were within Code limits after conservative stress range reduction factors were applied. The staff finds the response acceptable because the applicant indicated that the piping systems will continue to meet acceptable Code limits during the period of extended operation.

The LRA does not address the issue of underclad cracks. The WOG submitted for staff review Topical Report WCAP-15338, "A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants (MUHP-6110)" by letter dated March 1, 2001. WCAP-15338 indicates that underclad cracks are confined to forging materials, SA 508, Class 2 and 3. Topical Report WCAP-15338 also indicates that underclad cracks were observed in SA 508, Class 3 nozzles clad with multiple-layer, strip electrode, submerged-arc welding processes where preheating and post-heating were applied to the first layer but not to the subsequent layers. By letter dated January 28, 2002, the staff requested, in RAI 4.3-6, that the applicant provide additional information regarding the susceptibility of the McGuire/Catawba vessel forgings to underclad cracking. Subsequently, the staff identified the following information in Catawba UFSAR Section 5.3.1.4:

> **Section 5.3.1.4, "Special Controls for Ferretic and Austenitic Stainless Steels," page 5.3-2**
> **Regulatory Guide 1.43, "Control of Stainless Steel Weld Cladding of Low-Allow Steel Components (5/73)"**
>
> Discussion
>
> Westinghouse practices achieve the same purpose as Regulatory Guide 1.43 by requiring qualification of any high head input process, such as the submerged-arc wide-strip welding process and the submerged-arc 6-wire process used on ASME SA-508, Class 2, material, with a performance test as described in Regulatory Position 2 of the guide. No qualifications are required by the regulatory guide for ASME SA-533 material and equivalent chemistry for forging grade ASME SA-508, Class 3, material. The fabricator monitors and records the weld parameters to verify agreement with the parameters established by the procedure qualification as stated in Regulatory Position C.3.

Since Regulatory Guide (RG) 1.43 contains guidance for control of stainless steel cladding of low-alloy steel components, the staff concluded that underclad cracking was not a concern for Catawba 1 and 2. The staff was unable to verify that the same controls were in effect for the McGuire units. In its response dated April 15, 2002, the applicant did not provide adequate justification for the staff to conclude that all the McGuire reactor vessel forgings are not susceptible to underclad cracks.

By letter dated June 26, 2002, the staff provided a list of potential open items to the applicant and requested that the applicant provide written responses to resolve those open or confirmatory items that it considered reconcilable. RAI 4.3-6 was characterized as open for the McGuire units. In its response dated July 9, 2002, the applicant provided information that was excerpted from a letter dated May 12, 1980, in which the NRC requested information on the McGuire reactor vessel nozzle base metal material, clad process type, heat input, and manufacturer or subcontractor who fabricated the vessel and applied the nozzle cladding. The applicant also provided the following excerpt from a letter dated July 17, 1980, which transmitted the NRC's safety evaluation of information subsequently provided by Duke in a letter dated June 6, 2002:

> We have determined that the McGuire Unit No. 2 reactor vessel was fabricated by Rotterdam-Nuclear of the Netherlands using procedures for welding and pre- and post-clad heat treatments that increase the potential for underclad cracking. For this reason, we require that augmented ultrasonic examination for underclad cracking be performed on the McGuire Unit No. 2 reactor vessel nozzles prior to issuance of an operating license. The inspections should be conducted using techniques that have been designed to detect underclad cracks. These techniques previously have been used at Sequoyah 1, North Anna 2 and Salem 2. The McGuire Unit No. 1 vessel was fabricated by Combustion Engineering using welding heat treat practices expected not to cause underclad cracking. Therefore, we do not require that augmented preservice inspections be performed on the Unit No. 1 vessel. In the future augmented ultrasonic examinations will be required for a reactor vessel whose nozzles were clad in the U. S., but only as part of a program to verify that cladding heat treatments used by U. S. manufacturers do not result in underclad cracking.

Based upon this excerpt from the staff's safety evaluation regarding the reactor vessel nozzles at McGuire, the staff concludes that the applicant need not address this issue for McGuire 1. However, underclad cracking remains a concern for McGuire 2. The applicant is relying upon ultrasonic inspection for resolution of this issue. However, the staff believes that ultrasonic inspection is not effective at detecting defects of the size generated by this phenomenon. Therefore, this issue can be resolved for McGuire 2 only by analysis. For this reason, this issue was characterized as SER open item 4.3-3 and applied to McGuire 2 only.

In its response to SER open item 4.3-3, dated October 28, 2002, the applicant stated that Duke had compared the number of design cycles and transients used in the analysis contained in WCAP-15338 with the applicable number of design cycles and transients contained in McGuire Unit 2 design documents and verified that WCAP-15338 bounds the number of operating cycles and transients not only for McGuire 2 but also for Catawba Unit 1,[1] whose RV is also fabricated

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[1] As stated earlier in the evaluation provided in this section (page 4-14), the staff determined that RV underclad cracking was not an applicable effect for Catawba 1 because the RV forgings had been welded together in accordance with the recommended practices of Regulatory Guide (RG) 1.43, which, if implemented, should mitigate the amount of underclad cracking in the RV. However, the applicant has also indicated that the number of design cycles and transients in WCAP-15338 also bounds the number

from SA 508 Class 2 forging segments. In its response to SER open item 4.3-3, the applicant provided an FSAR supplement summary description to reflect that fatigue analysis in WCAP-15338 for RV underclad cracks in Westinghouse designed reactors was bounding for the evaluation for RV underclad cracks at McGuire 2. Since the conclusions in WCAP-15338 are bounding and applicable to the evaluation of fatigue-induced crack growth of underclad cracks in the McGuire 2 RV, the staff concludes that the applicant has demonstrated that its analysis for postulated underclad cracks in the McGuire 2 RV remains valid for the extended operating period for McGuire 2, and that therefore the applicant's TLAA for RV underclad cracks at McGuire 2 is acceptable pursuant to 10 CFR 54.21(c)(1)(i).

As discussed previously, the applicant relies on the TFMP to manage the thermal fatigue design basis to assure that the analyses remain valid for the period of extended operation. The staff review of the TFMP focused on how the program manages fatigue through effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, acceptance criteria, monitoring and trending, corrective actions, confirmation process, administrative controls and operating experience.

[Program Scope] The scope of the program includes the reactor coolant pressure boundary Class 1 components including piping connected to the RCS addressed by NRC Bulletins 88-08 and 88-11, replacement steam generators, components evaluated using fracture mechanics analyses, and four Catawba heat exchangers. The staff considers the scope of the program, which includes components with analyses that explicitly addressed thermal fatigue transient limits, acceptable.

[Preventive and Mitigative Actions] The applicant indicates that the TFMP ensures that the thermal fatigue design basis remains valid for the period of extended operation. The TFMP accomplishes this through the monitoring and tracking of transients used in the fatigue analyses of components. The staff did not identify a need for any further actions.

[Parameters Monitored or Inspected] The program monitors the transients used in the analyses of the components. The staff considers this monitoring appropriate because the program objective is to ensure that the analyses remain valid for the period of extended operation.

[Detection of Aging Effects] The program monitors the number of design transients used in the fatigue analysis of components to provide assurance that the fatigue analyses of record remain valid during the period of extended operation. The staff did not identify a need for any further actions.

[Monitoring and Trending] The program monitors the number of design transients used in the fatigue analysis of components. The program also monitors the pressure and temperature profiles of these transients. The monitored values are compared to design values. The staff considers this monitoring appropriate because the program objective is to ensure that the analyses remain valid for the period of extended operation.

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of design cycles and transients projected for Catawba 1 through the expiration of the extended period of operation. Each of these bases provide reasonable assurance that underclad cracking is not an issue for the Catawba 1 RV.

[Acceptance Criteria] The acceptance criteria are the number of cycles of each transient assumed in the design analyses and the temperature and pressure profiles for each transient. The staff considers this criteria acceptable because the program objective is to ensure that the analyses remain valid for the period of extended operation.

[Corrective Actions and Confirmation Process] The applicant indicates that, if the number of transient cycles approaches the assumed bases for the plant design, further analysis will be performed to account for the number of these cycles. The applicant also indicates that the corrective action program is triggered if the temperature or pressure profiles exceed the design limits. The staff's evaluation of the corrective action program and confirmation process is documented in Section 3.0.4 of this SER.

[Administrative Controls] The applicant indicates that implementation procedures are reviewed, approved, and maintained as controlled documents in accordance with the station's work process. The staff's evaluation of the administrative controls is documented in Section 3.0.4 of this SER.

[Operating Experience] The applicant indicates that thermal fatigue transients have been tracked since operation began at both McGuire and Catawba. The staff identified open item 4.3-1 regarding the applicant's response to issues identified in Topical Report WCAP-14574-A. Pending the completion of the staff's review of this issue, the staff is unable to conclude that operating experience has been adequately considered in the program.

4.3.3 FSAR Supplement

The applicant provided a McGuire FSAR supplement for Section 3.9.2 and a Catawba FSAR supplement for Section 3.9.3, which indicate that stress range reduction factors were used in the evaluation of ASME Class 2 and 3 piping systems. The applicant also provided a McGuire FSAR supplement for Section 5.2.1 and a Catawba FSAR supplement for Section 3.9.1 to indicate that both TFMP will continue to manage thermal fatigue into the period of extended operation. However, the applicant did not describe its commitment to evaluate the effects of the environment on fatigue of reactor coolant system pressure boundary components, and the applicant did not provide a description of its TFMP. Because these items should be described in a revised FSAR supplement, this issue was characterized as SER open item 4.3-4.

In its response dated October 28, 2002, the applicant provided FSAR supplements for Catawba and McGuire. The revised FSAR supplements provided summary descriptions of the TFMP for McGuire and Catawba. The revised FSAR supplements also included the applicant's commitment to perform additional evaluations of the effects of environmental fatigue on the critical locations identified in NUREG/CR-6260 prior to the period of extended operation. On the basis of the applicant's revised FSAR supplements for McGuire and Catawba, open item 4.3-4 is closed.

The staff concludes that the summary description of the applicant's actions to address metal fatigue for the period of extended operation provided in the revised McGuire and Catawba FSAR supplements satisfy the requirements of 10 CFR 54.21(d).

4.3.4 Conclusions

On the basis of its evaluation of McGuire and Catawba components, the staff concluded that the fatigue analysis of ASME Section III, Class 2 and 3 piping will remain valid for 60 years of operation. The applicant also has a TFMP to maintain a record of the transients used in the fatigue analyses of ASME Section III, Class 1 components and other components where thermal fatigue limits were explicitly addressed at McGuire and Catawba, and to ensure that the process will continue during the period of extended operation. The TFMP will provide assurance that the fatigue design of these components remains valid for the period of extended operation.

On the basis of its review, and with the resolution of SER open items 4.3-1, 4.3-2, 4.3-3, and 4.3-4, the staff concludes that the applicant's actions and commitments satisfy the requirements of 10 CFR 54.21(c)(1).

4.4 Environmental Qualification of Electrical Equipment

The aging (or qualified life) analysis for electrical components, included as part of the EQ program required by 10 CFR 50.49, that involve time-limited assumptions as defined by the current operating term for the McGuire and Catawba plants (i.e., 40 years), meets the 10 CFR 54.3 definition for TLAAs. The electrical components are thus considered TLAAs for license renewal. The EQ program, together with other plant programs/processes, has been evaluated, pursuant to 10 CFR 54.21(c)(1)(iii), to determine if they will adequately manage the effects of aging on the intended function(s) of electrical components for the period of extended operation.

In LRA Section 4.4, "Environmental Qualification (EQ) of Electric Equipment," the applicant described the technical bases and justification for why the McGuire and Catawba EQ Program, together with other plant programs/processes, adequately manages the effects of aging on the intended function(s) of electrical components for the period of extended operation. The staff reviewed this section of the LRA to determine whether the applicant had demonstrated that the effects of aging on the intended function(s) of electrical components will be adequately managed, through the McGuire and Catawba EQ Program, together with other plant programs/processes, during the period of extended operation as required by 10 CFR 54.21(c)(1)(iii).

4.4.1 Technical Information in the Application

The McGuire and Catawba EQ Program meets the requirements of 10 CFR 50.49. Section 50.49 of 10 CFR defines the scope of components to be included, requires the preparation and maintenance of a list of in-scope components, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics, and the environmental conditions to which the components could be subjected. Section 50.49(e)(5) of 10 CFR contains provisions for aging that require, in part, consideration of all significant types of aging degradation that can affect component functional capability. Section 50.49(e) of 10 CFR also requires replacement or refurbishment of components not qualified for the current license term prior to the end of designated life, unless additional life is established through ongoing qualification. Section 50.49(f) of 10 CFR establishes four methods of demonstrating qualification for aging and accident conditions. Sections 50.49(k) and (l) of 10 CFR permit different qualification criteria to apply based on plant and component vintage. Compliance with 10 CFR 50.49 provides reasonable assurance that the component can perform its intended functions during accident conditions after experiencing the effects of inservice aging.

The McGuire and Catawba EQ Program manages component thermal, radiation, and cyclical aging, as applicable, through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation.

Under 10 CFR 54.21(c)(1)(iii), the McGuire and Catawba EQ Program, which implements the requirements of 10 CFR 50.49, is viewed as an aging management program for license renewal. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria and corrective actions (if acceptance criteria are not met).

The reanalysis of an aging evaluation is normally performed to extend the qualification by reducing excess conservatism incorporated in the prior evaluation. Reanalysis of an aging evaluation to extend the qualification of a component is performed pursuant to 10 CFR 50.49(e) as part of the McGuire and Catawba EQ Program. While a component's life-limiting condition may be due to thermal, radiation, or cyclical aging, the vast majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed ambient temperature of the component, an unrealistically low activation energy, or in the application of a component (de-energized versus energized). The reanalysis of an aging evaluation is documented according to McGuire and Catawba quality assurance program requirements, which requires the verification of assumptions and conclusions. As already noted, important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). These attributes are discussed below.

Analytical Methods: The McGuire and Catawba EQ Program uses the same analytical models in the reanalysis of an aging evaluation as those previously applied during the prior evaluation. The Arrhenius methodology is an acceptable thermal model for performing a thermal aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose (i.e., normal radiation dose for the projected installed life plus accident radiation dose). For license renewal, one acceptable method of establishing the 60-year normal radiation dose is to multiply the 40-year normal radiation dose by 1.5. The result is added to the accident radiation dose to obtain the total integrated dose for the component. For cyclical aging, a similar approach may be used. Other models may be justified on a case-by-case basis.

Data Collection and Reduction Methods: Reducing excess conservatism in the component service conditions (e.g., temperature, radiation, cycles) used in the prior aging evaluation is the chief method used for a reanalysis per the McGuire and Catawba EQ Program. Temperature data used in an aging evaluation should be conservative and based on plant design temperatures or on actual plant temperature data. When used, plant temperature data can be obtained in several ways, including monitors used for technical specification compliance, other installed monitors, measurements made by plant operators during rounds, and temperature sensors on large motors (while the motor is not running). A representative number of temperature measurements are conservatively evaluated to establish the temperatures used in an aging evaluation. Plant temperature data may be used in an aging evaluation in different ways, such as (1) directly applying the plant temperature data in the evaluation, or (2) using the plant temperature data to demonstrate conservatism when using plant design temperatures for an evaluation. Any changes to material activation energy values as part of a reanalysis are to be justified on a plant-specific basis. Similar methods of reducing excess conservatism in the component service conditions used in prior aging evaluations can be used for radiation and cyclical aging.

Underlying Assumptions: McGuire and Catawba EQ Program component aging evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant modifications and events. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions.

Acceptance Criteria and Corrective Action: Under the McGuire and Catawba EQ Program, the reanalysis of an aging evaluation could extend the qualification of the component. If the qualification cannot be extended by reanalysis, the component must be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner (i.e., sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful).

In addition to these important attributes for reanalysis of the aging evaluation, the McGuire and Catawba EQ Program includes the attributes described below:

<u>McGuire and Catawba EQ Program</u>

[Program Scope] The McGuire and Catawba EQ Program includes certain electrical components that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49.

[Preventive Actions] Section 50.49 of 10 CFR does not require actions that prevent aging effects. McGuire and Catawba EQ Program actions that could be viewed as preventive actions include (1) establishing the component service condition tolerance and aging limits (e.g., qualified life or condition limit), and (2) where applicable, requiring specific installation, inspection, monitoring, or periodic maintenance actions to maintain component aging effects within the bounds of the qualification basis.

[Parameters Monitored or Inspected] The qualified life of a component in the McGuire and Catawba EQ Program is not based on condition or performance monitoring. However, pursuant to Regulatory Guide 1.89, Rev. 1, such monitoring programs are an acceptable basis to modify a qualified life through reanalysis. Monitoring or inspection of certain environmental conditions or component parameters may be used to ensure that the component is within the bounds of its qualification basis, or as a means to modify the qualified life.

[Detection of Aging Effects] Section 50.49 of 10 CFR does not require the detection of aging effects for inservice components. As implemented by the McGuire and Catawba EQ Program, monitoring or inspection of certain environmental conditions or component parameters may be used to ensure that the component is within the bounds of its qualification basis, or as a means to modify the qualified life.

[Monitoring and Trending] Section 50.49 of 10 CFR does not require monitoring and trending of component condition or performance parameters of inservice components to manage the effects of aging. McGuire and Catawba EQ Program actions that could be viewed as monitoring include monitoring how long qualified components have been installed. Monitoring or inspection of certain environmental, condition, or component parameters may be used to ensure that a component is within the bounds of its qualification basis or as a means to modify the qualification.

[Acceptance Criteria] Section 50.49 of 10 CFR acceptance criteria, as implemented by the McGuire and Catawba EQ Program, are that an inservice EQ component is maintained within the bounds of its qualification basis, including (1) its established qualified life and (2) continued qualification for the projected accident conditions. Section 50.49 of 10 CFR requires refurbishment, replacement, or requalification prior to exceeding the qualified life of each installed device. When monitoring is used to modify a component qualified life, plant-specific acceptance criteria are established based on applicable 10 CFR 50.49(f) qualification methods.

[Corrective Action and Confirmation Process] If a component in the McGuire and Catawba EQ Program is found to be outside the bounds of its qualification basis, corrective actions are implemented in accordance with the station's corrective action program. When unexpected adverse conditions are identified during operational or maintenance activities that affect the environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. When an emerging industry aging issue is identified that affects the qualification of an EQ component, the affected component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. Confirmatory actions, as needed, are implemented as part of the McGuire and Catawba corrective action program, pursuant to 10 CFR 50, Appendix B.

[Administrative Controls] The McGuire and Catawba EQ Program is implemented through the use of station policy, directives, and procedures. The McGuire and Catawba EQ Program will continue to comply with 10 CFR 50.49 throughout the renewal period, including development and maintenance of qualification documentation demonstrating reasonable assurance that a component can perform required functions during harsh accident conditions. McGuire and Catawba EQ Program documents identify the applicable environmental conditions for the component locations. McGuire and Catawba EQ Program qualification files are maintained at McGuire and Catawba in an auditable form for the duration of the installed life of the component. McGuire and Catawba EQ Program documentation is controlled under the station's quality assurance program.

[Operating Experience] EQ programs include consideration of operating experience to modify qualification bases and conclusions, including qualified life. Compliance with 10 CFR 50.49 provides reasonable assurance that components can perform their intended functions during accident conditions after experiencing the effects of inservice aging.

Based on the above described attributes for reanalysis of the aging evaluation and EQ program, the applicant concluded that the McGuire and Catawba EQ Program has been demonstrated to be capable of programmatically managing the qualified lives of the components falling within the scope of the program for license renewal. The continued implementation of the McGuire and Catawba EQ Program provides reasonable assurance that the aging effects will be managed and that components falling within the scope of the EQ Program will continue to perform their intended functions for the period of extended operation. This result meets the requirement of 10 CFR 54.21(c)(1)(iii).

4.4.2 Staff Evaluation

The staff reviewed the information in Sections 4.4, 4.4.1, 4.4.2, and 4.4.3 of the LRA to determine whether the applicant has demonstrated that the effects of aging on the intended function(s) of electrical components will be adequately managed through their existing EQ program, together with other plant programs/processes, during the period of extended operation as required by 10 CFR 54.21(c)(1)(iii).

The applicant is required to have an EQ program that meets the requirements of 10 CFR 50.49. The staff, therefore, agrees with the applicant's conclusion that their EQ program, together with other plant programs/processes, will adequately manage the effects of aging on the intended function(s) of electrical components for the period of extended operation. The staff therefore concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that their EQ program, together with other plant programs/processes, will adequately manage the effects of aging on the intended functions and can be considered an acceptable aging management program for license renewal.

<u>Generic Safety Issue (GSI) -168, Environmental Qualification of Electrical Equipment</u>

This GSI was developed to address environmental qualification of electrical equipment. By letter from C. Grimes (NRC staff) to D. Walters (NEI), dated June 2, 1998, the staff issued the following guidance to the industry:

- GSI-168 issues have not been identified to a point that a license renewal applicant can be reasonably expected to address these issues specifically at this time
- An acceptable approach is to provide a technical rationale demonstrating that the CLB for EQ will be maintained in the period of extended operation

For the purpose of license renewal, there are three options for addressing issues associated with a GSI, as discussed in the statement of considerations (SOC) accompanying the final rule, 60 FR 22484, May 8, 1995:

(1) If the issue is resolved before the renewal application is submitted, the applicant can incorporate the resolution into the LRA.
(2) An applicant can submit a technical rationale that demonstrates that the CLB will be maintained until some later point in the period of extended operation, at which time one or more reasonable options would be available to adequately manage the effects of aging.
(3) An applicant can develop a plant-specific aging management program that incorporates a resolution to the aging issue.

The applicant did not provide information in Section 4.4 to address the GSI-168 options. In electronic correspondence from the applicant, dated June 17, 2002 (ADAMS Accession No. ML022200637), Duke provided the following account of GSI-168 as it applies to McGuire and Catawba:

> As discussed in SECY-93-049, the staff reviewed significant license renewal issues and found that several were related to environmental qualification (EQ). A key aspect of these issues was whether the licensing bases should be reassessed or enhanced in connection with license renewal, and whether this reassessment should be extended to the current license term. In late 1993, the Commissioners instructed the staff that the current EQ licensing basis must be used in the license renewal period and that any EQ concerns identified by the staff during the review of EQ for license renewal should be evaluated for the effect on current licenses, independent of license renewal.
>
> The NRC Staff's EQ Task Action Plan (EQ-TAP) was initiated to address the adequacy of current EQ practices. Upon completion of the EQ-TAP review, the focus of Staff concerns was limited to issues related to the adequacy of accelerated aging practices in existing qualifications, and the lack of a "feedback mechanism" in EQ programs (i.e., programmatic requirements to determine the current condition of EQ equipment so that it can be evaluated against the assumptions and parameters for qualification). The EQ-TAP was subsequently closed and six remaining open issues were incorporated into GSI 168 for management tracking purposes. The EQ-TAP review did not identify any generic safety issues related to these six open issues.
>
> NRC guidance for addressing GSI 168 for license renewal is contained in a June 1998 letter to NEI. In this letter, the NRC states:
>
> With respect to addressing GSI 168 for license renewal, until completion of an ongoing research program and staff evaluations, the potential issues associated with GSI 168 and their scope have not been defined to the point that a license renewal applicant can reasonably be expected to address them at this time. Therefore, an acceptable approach described in the SOC is to provide a technical rationale demonstrating that the current licensing basis for EQ pursuant to 10 CFR 50.49 will be maintained in the period of extended operation. Although the SOC also indicates that an applicant should provide a brief description of one or more reasonable options that would be available to adequately manage the effects of aging, the staff does not expect an applicant to provide the options at this time.
>
> Environmental qualification evaluations of electrical equipment are identified as time-limited aging analyses for McGuire and Catawba. The McGuire and Catawba EQ program evaluations contained in Section 4.4 of the Application are considered to be the technical rationale that the current licensing basis will be maintained during the period of extended operation. Consistent with the above NRC guidance, no additional information is required to address GSI 168 in a renewal application at this time.

By letter dated July 9, 2002, the applicant provided this same response in official correspondence. The staff finds that the applicant has submitted, in accordance with the SOC, a technical rationale that demonstrates that the CLB will be maintained until some later point in the period of extended operation, at which time one or more reasonable options would be available to adequately manage the effects of aging. However, the staff requested that the applicant also indicate that it would monitor updates to NUREG-0933, "A Prioritization of Generic Safety Issues," for revisions to GSI-168 during the review of its application, or that it would supplement its license renewal application if the issues associated with GSI-168 become defined, such that providing the options or pursuing one of the other approaches described in the SOC becomes feasible. Pending the staff's receipt of this information, this issue was characterized as confirmatory item 4.4-1.

In response to confirmatory item 4.4-1, dated October 2, 2002, the applicant proposed the following alternative commitment:

> If the staff issues a generic communication that defines the issues associated with GSI-168 such that providing the options or pursuing one of the other approaches described in the SOC to 10 CFR 54 (FR Vol. 60, No. 88, May 8, 1995) becomes feasible, then Duke will supplement its license renewal application. The staff generic communication should be issued prior to November 1, 2002 in order for Duke to evaluate its contents, prepare a response as a current licensing basis change, if any is required, and provide a supplement to the application (if necessary) in sufficient time for the staff to complete its review prior to the scheduled issuance of the safety evaluation report for license renewal January 6, 2003.

The resolution to GSI-168 was not issued by the staff prior to November 1, 2002; thus, the applicant's proposed alternative commitment is their original commitment that was stated above in their June 17, 2002, response to GSI-168. Pursuant to the requirements of 10 CFR Part 50, the staff will evaluate the applicant's compliance to the resolution of GSI-168 after its issuance and prior to the extended period of operation as part of 10 CFR 50.49. Resolution of GSI-168 pursuant with Part 50 meets the requirement of 10 CFR 54.21(c)(1)(iii) and is therefore considered acceptable. Confirmatory item 4.4-1 is considered closed.

4.4.3 FSAR Supplement

In LRA Appendix A, pages A.1-5 and A.2-7, the applicant states that the existing EQ process, in accordance with 10 CFR 50.49, will adequately manage aging of EQ equipment for the period of extended operation. This statement is consistent with the conclusion that plant EQ programs, which implement the requirements of 10 CFR 50.49, are viewed as acceptable aging management programs for license renewal under 10 CFR 54.21(c)(1)(iii). This statement thus provides a summary description of the programs and activities for the evaluation of TLAA for the period of extended operation for electrical components, meets the requirements of 10 CFR 54.21(d), and is considered acceptable.

4.4.4 Conclusions

The staff has reviewed the information in Sections 4.4, 4.4.1, 4.4.2, and 4.4.4 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the effects of aging on the intended function(s) of electrical components, that meet the definition for TLAA, as defined in 10 CFR 54.3, will be adequately managed during the period of extended operation as required by 10 CFR 54.21(c)(1)(iii). The staff concludes that the FSAR supplement contains a summary description of the programs and activities for the evaluation of TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.5 Concrete Containment Tendon Prestress

4.5.1 Technical Information in the Application

The applicant stated that this topic is not applicable to the McGuire and Catawba ice condenser containments. Ice condenser containments do not use prestressed tendons.

4.5.2 Staff Evaluation

The staff concurs with the applicant that this topic is not applicable, and prestress of the concrete containment tendons at the McGuire and Catawba plants is therefore not a TLAA.

4.5.3 Conclusions

The staff finds the applicant's statement that this topic is not applicable to McGuire and Catawba acceptable.

4.6 Containment Liner Plate, Metal Containments, and Penetration Fatigue Analysis

4.6.1 Technical Information in the Application

The applicant stated that McGuire and Catawba have ice condenser metal containments, and therefore do not have containment liner plates, like prestressed concrete containments. The topic of fatigue analysis for containment liner plates is therefore not applicable to these plants.

The McGuire and Catawba ice condenser containments are steel containment vessels (SCVs), described in Section 2.4 of the LRA. The Design Code of Record for the McGuire SCV is the "ASME Boiler & Pressure Vessel Code," Section III, Subsection B, 1968 Edition, including all addenda and code cases through the summer of 1970. The Code of Record for Catawba is the "ASME Boiler & Pressure Vessel Code," Section III. Subsection NE, 1971 Edition, including all addenda through the summer of 1972.

The SCV contain piping through-wall hot and cold mechanical penetration assemblies. Typical hot penetration assemblies are shown in the McGuire and Catawba UFSARs. The hot penetrations consist of the process line and flued head, the guard pipe, and the expansion bellows. The bellows are designed to accommodate process line thermal expansions and displacements between the SCV and the reactor building due to cyclic thermal expansion, seismic movements, and containment test conditions, and to act as barriers against the release of fission products during design basis events. Fatigue is a progressive failure of a structural part under repeated, cycling, or fluctuating loads. Because of the bellows design, the bellows absorb the cyclic piping loads that could cause fatigue and are not transferred to the SCV. Therefore, no fatigue analysis was required for the SCV, and containment fatigue is not a TLAA for either McGuire or Catawba.

All bellows expansion joints are of two-ply construction with a wire mesh between plys for testability of the bellows and the bellows welds to the piping. The McGuire bellows were manufactured, installed, and examined in accordance with paragraph NC-3649 of the ASME Code, Section III, 1971 Edition. The design requirements are contained in McGuire engineering documents. As part of the design, the Code required the manufacturer to consider combined stresses due to pressure and relative displacement due to thermal expansion. The cyclic life data for the bellows was based on actual tests, where bellows designs similar to those installed were cycled to failure. A search of the applicant's engineering records did not locate any manufacturer's records for a fatigue calculation on the original design of the McGuire bellows. During later modifications at McGuire, the bellows manufacturer reviewed the design for revised feedwater penetration movements, and determined that these were good for over 32,000 cycles, considerably in excess of the number of cycles that the bellows would see under normal operating conditions.

For Catawba, the bellows assemblies were manufactured, installed, and examined in accordance with paragraph NC-3649 of the ASME Code, Section III, 1974 Edition. The design requirements for these bellows are contained in Catawba engineering documents. The manufacturer has provided calculations to the applicant for the cyclic life evaluation of the penetrations. These cyclic life values were used by the manufacturer to demonstrate that the design met the Code requirements.

For McGuire and Catawba, the applicant stated that the fatigue analysis of the bellows was determined not to be relevant in making any safety determination. On this basis, the fatigue of bellows is not a TLAA because Criterion 4 of the 10 CFR 54.3 definition of a TLAA was not met. However, the aging effect which could result from cyclic fatigue, cracking, has been identified as an aging effect for the bellows, requiring management for the period of extended operation. Local leak rate testing has been identified as the general program that includes managing of cracking of the bellows. Local leak rate testing is discussed as part of LRA Appendix B.3.8, Containment Leak Rate Testing Program.

4.6.2 Staff Evaluation

By letter dated January 28, 2002, the staff requested, in RAI 4.6-1, that the applicant provide a detailed justification for determining that a fatigue TLAA was not required for the SCV for loadings resulting from operating transients, peak containment internal pressure resulting from the design basis LOCA, design basis safe shutdown earthquake (SSE) and leakage rate testing, in addition to the loading resulting from the transient expansions of the bellows. In its response dated March 11, 2002, the applicant stated that the penetration bellows are provided to absorb the loads associated with thermal expansion during operational transients, as well as loads induced during the containment leak testing. Peak containment internal pressure resulting from the design basis LOCA or a design basis SSE are one-time occurrences and not cyclic loads that could cause fatigue failure. The SCV is, therefore, not subjected to cyclic loading and as a result, no fatigue analysis was necessary or performed. The staff finds the response to the RAI acceptable and considers the issue resolved.

Operating experience with containment bellows at both McGuire and Catawba, as reported in LRA Appendix B, Section B.3.8, indicates that leaks were detected during containment leakage tests within 20 years of the start of plant operation. During a conference call between the staff and the applicant on November 20, 2001, summarized by memorandum dated January 10, 2002, the applicant stated that 20 leaking bellows at McGuire and 3 leaking bellows at Catawba were identified during testing. However, these bellows were not replaced as long as leakage did not exceed TS surveillance acceptance criteria. Since the bellows were not replaced, root cause evaluations were not performed to determine the cause (fatigue or SCC) of the leakage. Therefore, the applicant indicated that bellows leakage during the tests could not be attributed definitively to cracking by fatigue and that some other cause may be responsible. By letter dated January 28, 2002, the staff requested, in RAI 4.6-2, that the applicant provide the root cause of the cracking (leakage), since the vendors of the bellows performed cyclic fatigue life evaluations and stated that the life of the bellows is well beyond what the bellows would experience during 40 years of normal plant operation.

In its response to RAI 4.6-2, dated March 11, 2002, the applicant stated that since leakage of the bellows is not attributed to cyclic fatigue, the vendor-analyzed cyclic life remains valid for the period of extended operation. The applicant stated that the leakage during the tests could be attributed to transgranular stress corrosion cracking from contact with a chlorine environment and other causes, such as manufacturing process defects, improper installation, and damage incurred during construction or maintenance activities. The potential leakage that could result from any one of these causes is managed by the Containment Leak Rate Testing Program. This program is identified in Table 3.5-1 of the LRA as a program for managing bellows cracking that would manifest itself during the leakage testing. The staff finds the response to this RAI acceptable and considers this issue resolved.

During the conference call on November 20, 2001, the applicant stated that the calculations and analyses for bellows were not considered relevant in making a safety determination, and that aging of these components would be managed by an aging management program. By letter dated January 28, 2002, the staff requested, in RAI 4.6-3, that the applicant clarify this statement. In its response dated March 11, 2002, the applicant stated that a cyclic analysis of the bellows had been originally performed, but the number of cycles to failure was too large to preclude any safety judgement based on this number. Since this analysis was not used as the basis for any safety judgement, the analysis does not meet Criterion 4 of 10 CFR 54.3 for the definition of a TLAA as defined in 10 CFR 54.3. Because the function of the bellows is within the scope of license renewal, and leaks have been observed at both McGuire and Catawba, cracking has been identified as an aging effect for bellows in Table 3.5-1 of the Application. Aging of penetration bellows will therefore be managed under the Containment Leak Rate Testing Program, discussed in LRA Appendix B, Section B.3.8. The staff's evaluation of the AMP is documented in Section 3.0.3.4 of this SER. Since the Containment Leak Rate Testing Program will reveal leakage (cracks) caused by both fatigue and SCC, the staff finds this response acceptable and considers this issue resolved.

4.6.3 FSAR Supplement

The applicant has not provided a supplement to the FSAR, since no new information regarding Section 4.6 was provided in the Application.

4.6.4 Conclusions

On the basis of its review, and the responses to the staff requests for additional information, the staff concludes that the applicant has provided adequate information and reasonable assurance to demonstrate that, pursuant to 10 CFR 54.21(c)(iii), the effects of aging of the containment penetration bellows will be adequately managed for the period of extended operation.

4.7 Other Plant-Specific Time-Limited Aging Analyses

4.7.1 Reactor Coolant Pump Flywheel Fatigue

4.7.1.1 Technical Information in the Application

The applicant has addressed the TLAA related to fatigue of the reactor coolant pump (RCP) flywheel in Section 4.7.1 of the LRA. The RCP motors at McGuire and Catawba are of the same design. The RCP motors are large, vertical, squirrel cage, induction motors. The motors have flywheels to increase rotational inertia, thus prolonging pump coastdown and assuring a more gradual loss of main coolant flow to the core in the event that pump power is lost. The flywheel is mounted on the upper end of the rotor, below the upper radial bearing and inside the motor frame. The aging effect of concern is fatigue crack initiation in the flywheel bore keyway from stresses due to starting the motor. Therefore, this topic is considered as a TLAA for license renewal based on the criteria contained in 10 CFR 54.3.

4.7.1.2 Staff Evaluation

The applicant estimates that the existing analysis is valid for the period of extended operation, meeting the requirements of 10 CFR 54.21(c)(1).

To estimate the magnitude of fatigue crack growth during plant life, an initial radial crack length of 10 percent of the distance through the flywheel (from the keyway to the flywheel outer radius) was conservatively assumed. The analysis assumed 6000 cycles of pump starts and stops for a 60-year plant life. Reaching 6000 starts in 60 years would require a pump start, on average, every 3.7 days. Since a pump start normally occurs every 200 to 300 days, on average, the design of the reactor coolant pump flywheels is conservative. In addition, crack growth from postulated flaws in each flywheel is only a few mils[2]. The staff concurs with the applicant's assessment and the assumptions made in arriving at the above estimate of pump starts.

4.7.1.3 FSAR Supplement

The staff has reviewed the changes in the FSAR supplement to existing Section 3.5.2.1 of the UFSAR, provided in Appendices A-1 and A-2 of the LRA for McGuire and Catawba, respectively, and has confirmed that these changes are appropriate because they reflect the validity of the analysis for 60 years of operation.

4.7.1.4 Conclusions

Because the applicant has demonstrated that the existing analysis for the RCP flywheel is valid for 60 years of operation, the staff concludes that the applicant has provided an acceptable TLAA involving components of the RCP flywheel, as defined in 10 CFR 54.21(c)(1)(i).

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[2] WCAP-14535A, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination"

4.7.2 Leak-Before-Break Analyses

The applicant's leak-before-break analysis is provided in Section 4.7.2 of the LRA.

4.7.2.1 Technical Information in the Application

The successful application of leak-before-break (LBB) to the McGuire reactor coolant system primary loop piping is described in Technical Report WCAP-10585, "Technical Basis for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for McGuire Units 1 and 2." Likewise, the successful application of LBB to the Catawba reactor coolant system primary loop piping is described in Technical Report WCAP-10546, "Technical Basis for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Catawba Units 1 and 2." These reports provide the technical basis for evaluating postulated flaw growth in the main reactor coolant system piping under normal plus faulted loading conditions.

The applicant stated that there are two considerations for the LBB analysis. The first analysis consideration is that the material properties of the cast austenitic stainless steel can change over time. Cast austenitic stainless steels used in the reactor coolant system are subject to thermal aging during service. This thermal aging causes an elevation in the yield strength of the material and a degradation of the fracture toughness, the degree of degradation being a function of the level of ferrite in the material. Thermal aging in these stainless steels will continue until a saturation or fully aged point is reached.

NRC-approved Technical Report WCAP-10456, "The Effects of Thermal Aging on the Structural Integrity of Cast Stainless Steel Piping for Westinghouse Nuclear Steam Supply Systems," presented a detailed study of the effects of thermal aging on piping integrity. This report concluded that the thermal aging process does not significantly change the failure characteristics of the cast stainless steel piping. Technical Reports WCAP-10585 (McGuire) and WCAP-10546 (Catawba) used the findings of this report to make the determination that the material properties in WCAP-10456 were bounding for McGuire and Catawba. Fully aged, lower bounding data were used in performing the LBB evaluation. Additionally, during the license renewal review, the lower bound data in WCAP-10456 were compared to the lower bound data in NUREG-6177, "Assessment of Thermal Embrittlement of Cast Stainless Steels," and found to be comparable. Therefore, because the original analysis supporting LBB relied on fully aged stainless steel material properties, the analysis does not have a material property time-dependency that requires further evaluation for license renewal.

The second analysis consideration is the accumulation of actual fatigue transient cycles over time that could invalidate the fatigue flaw growth analysis that was done as part of the original LBB analysis. A review of the accumulation of the applicable fatigue transient cycles is considered to meet the TLAA definition. This review was done within the scope of the thermal fatigue management program. The applicant stated that the continued implementation of the thermal fatigue management program provides reasonable assurance that thermal fatigue will be managed for the Class I components such that they will continue to perform their intended function(s) for the period of extended operation.

4.7.2.2 Staff Evaluation

In the LRA regarding LBB, the applicant intended to demonstrate, through qualitative assessment, that the plant-specific thermal fatigue management program is capable of programmatically managing the assumptions, including the fatigue cycles, in the existing LBB analyses for the period of extended operation. The staff confirmed that the LBB applications for the primary loop piping were approved by the NRC on April 7, 1987, for Catawba 1; on April 23, 1985, for Catawba 2; and on May 5, 1986, for McGuire 1 and 2. The LBB analyses, which provided technical bases for these approved LBB applications, considered the thermal aging of the cast austenitic stainless steel material of the piping, assuming 40 years of operation. Since the primary loop piping contains cast stainless steel material, the LBB application is a TLAA for both plants.

The thermal aging of the cast stainless steel material has been identified as an issue to be reevaluated. This reevaluation revealed that the original LBB analyses had employed the thermal aging properties documented in Technical Report WCAP-10456, "The Effects of Thermal Aging on the Structural Integrity of Cast Stainless Steel Piping for Westinghouse Nuclear Steam Supply Systems," which bounded the aging material data for Catawba and McGuire. In addition, the applicant performed a comparison of the material aging information in WCAP-10456 with the more recent information in NUREG-6177, and found that the WCAP-10456 toughness data, after long-term aging considering fluence, time, operating temperature, chemical composition, and ferrite content, were bounding. The staff has examined the information in the above-mentioned documents and agreed with the applicant's conclusion that fully aged, lower bounding material property was used in the original LBB analyses. Hence, the properties for the cast stainless steel piping material are acceptable because they will not degrade below the fully aged properties in the extended period of operation.

For the rest of the primary loop piping materials, instead of revising the original analyses by taking into account the fatigue transient cycles for the period of extended operation, the applicant relies on the plant-specific thermal fatigue management program to ensure that the accumulation of the applicable fatigue transient cycles over time would not invalidate the fatigue flaw growth analysis that was performed as part of the original LBB analyses. With this program in place, which calls for constant review of the accumulation of applicable fatigue transient cycles, the applicant concluded that "the continued implementation of the thermal fatigue management program provides reasonable assurance that thermal fatigue will be managed for the Class 1 components such that they will continue to perform their intended function(s) for the period of extended operation." The staff has reviewed the thermal fatigue management program and determined that the three monitoring actions of the program are adequate to monitor the applicable set of transients and their limits, and to count the actual thermal cycle transients to ensure that it is within the allowable limits of the defined transients.

In the event that the pressure and temperature profile for a specific transient is outside the parameters for the defined transient set, or the actual cycle count for a transient set is approaching or exceeding the cycle limit assumed in the original LBB analyses, the applicant proposed to take corrective actions, such as conducting ISI activities, implementing plant modifications, and performing revised analyses. The staff considers these measures appropriate and agrees with the applicant's conclusion that this TLAA is in accordance with 10 CFR 54.21(c)(1)(ii), and the continued implementation of the thermal fatigue management program provides reasonable assurance that thermal fatigue will be managed for the primary loop piping and components such that it will continue to perform its intended function for the period of extended operation.

Since the V.C. Summer main coolant loop weld cracking event involving Alloy 82/182 weld material, the staff has been addressing the effect of primary water stress corrosion cracking (PWSCC) on Alloy 82/182 piping welds on a generic basis for all currently operating PWR plants. To resolve this current operating issue, the industry is taking the initiative to (1) develop overall inspection and evaluation guidance, (2) assess the current inspection technology, and (3) assess the current repair and mitigation technology. An interim industry report, "PWR Materials Reliability Project Interim Alloy 600 Safety Assessment for US PWR Plants (MRP-44), Part 1: Alloy 82/182 Pipe Butt Welds," was published in April 2001 to justify the continued operation of PWR plants while the industry completes the development of the final report. The staff documented its acceptance of this interim report in a safety evaluation issued June 14, 2001. The final industry report on this issue has not yet been published. Pending its receipt of the final report and additional UT inspection data from piping involving Alloy 82/182 weld material from the industry, the staff is pursuing resolution of this current operating issue pursuant to 10 CFR Part 50. Additionally, the staff identified SER open item 3.0.3.10.2-2 and requested the applicant to (1) identify the locations in the McGuire and Catawba RCS piping that contain Alloy 82/182 welds, and (2) describe actions it has taken to address this operating experience as it applies to McGuire and Catawba. The resolution of this open item is documented in Section 3.0.3.10.2 of this SER.

4.7.2.3 FSAR Supplement

The applicant provided a McGuire FSAR supplement for Section 5.2.1 and a Catawba FSAR supplement for Section 3.9.1 to indicate that LBB analyses evaluate postulated flaw growth in the primary loop piping of the RCS. In addition to the summary description, the FSAR supplements contain information regarding the consideration of thermal aging of cast austenitic stainless steel and the applicable crack growth calculations under the thermal fatigue management program, which constitute the bases for the staff's acceptance of the applicant's evaluation of the LBB TLAA for the period of extended operation. Therefore, the supplements meet the requirements of 10 CFR 54.21(d) and are considered acceptable.

4.7.2.4 Conclusions

The properties for the cast stainless steel piping material are acceptable because they will not degrade below the fully aged properties in the extended period of operation. Furthermore, the thermal fatigue management program is adequate to ensure that allowable limits are maintained. The applicant has proposed to take appropriate corrective actions if the pressure and temperature profile for a specific transient is outside the parameters for the defined transient set, or the actual cycle count for a transient set is approaching or exceeding the cycle limit. With respect to the potential for PWSCC of the 82/182 welds, the staff is pursuing resolution of this current operating issue pursuant to 10 CFR Part 50. Any measures to be implemented, or any requirements to be imposed, as part of the resolution of the PWSCC issue under 10 CFR Part 50 also will apply during the period of extended operation. Therefore, the staff concludes that the applicant has provided an acceptable TLAA regarding LBB and meets 10 CFR 54.21 (c)(1)(ii).

4.7.3 Depletion of Nuclear Service Water Pond Volume Due to Run-Off

The depletion of nuclear service water pond volume due to run-off time-limited aging analysis is not applicable at McGuire. The drainage area serving the McGuire nuclear service water ponds is such that the run-off and resulting sedimentation are negligible. The volume of the McGuire nuclear service water pond has been previously reviewed and accepted by the NRC in the initial McGuire SER, Section 4.2[3].

The depletion of nuclear service water pond volume due to run-off TLAA is applicable to Catawba, which is provided in Section 4.7.3 of the LRA.

4.7.3.1 Technical Information in the Application

The standby nuclear service water (SNSW) pond is a nuclear safety-related impoundment constructed by placing a dam across a small cove of Lake Wylie. Because of the design of the SNSW pond, an analysis was performed to predict the total loss of volume in the pond due to sedimentation during the 40-year plant life. This analysis is described in the Catawba UFSAR, Section 2.4.8, and the Catawba SER, Section 2.4.4.2. The analysis estimated that the SNSW pond volume would be depleted by about 10 acre-feet of sediment during the 40-year plant life.

Because all of the criteria contained in 10 CFR 54.3 have been met, the sedimentation of the SNSW pond, over time, is a time-limited aging analysis for Catawba Nuclear Station. TLAA demonstration option (iii), which states that the effects of aging will be adequately managed for the period of extended operation, is chosen to manage the SNSW pond sedimentation TLAA. The Standby Nuclear Service Water Pond Volume Program manages the volume of water in the pond.

Catawba TS 3.7.9.1 requires that the water level of the SNSW pond remain greater than or equal to 571 feet mean sea level. This requirement ensures that a sufficient volume of water is available to allow the nuclear service water system to operate for at least 30 days following the design basis LOCA. The SNSW pond's level is monitored and makeup water is provided should the pond level drop to 571.5 feet. TS 3.7.9 requires immediate makeup to restore the pond level or the station is shut down. The minimum allowable pond level includes a margin to account for evaporation and the use of SNSW pond water for fire protection, assured auxiliary feedwater, assured component cooling makeup, and assured fuel pool makeup for a full 30 days after a postulated accident, according to Section 9.2.5.4 of the Catawba UFSAR.

Catawba UFSAR Figure 9-54 contains the area volume curves which are used in the thermal analysis for the ultimate heat sink. The UFSAR also includes a commitment that soundings will be taken around the SNSW intake structure at 5-year intervals to assure that sediment deposits will not adversely affect the operation of the nuclear service water system. Although an earlier calculation for the volume of the SNSW pond was documented, more recent calculations have been performed which validate the volume of water in the SNSW pond.

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[3] NUREG-0422, "Safety Evaluation Report Related to the Operation of the McGuire Nuclear Station, Units 1 and 2."

4.7.3.2 Staff Evaluation

The applicant has chosen to utilize TLAA demonstration option (iii). The staff evaluation of the TLAA, therefore, focused on how the SNSW Pond Volume Program manages the aging effect of pond volume depletion through 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.

It is noted that corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR, Part 50, Appendix B, and cover all structures and components subject to an aging management review. The staff's evaluation of the applicant's corrective actions, confirmation process and administrative controls is documented in Section 3.0.4 of this safety evaluation report. This program satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining seven elements are discussed below.

<u>Standby Nuclear Service Water Pond Volume Program</u>

[Program Scope] The scope of the Standby Nuclear Service Water Pond Volume Program includes the volume of water in the SNSW pond. The staff finds the scope of the program acceptable because this is the only commodity in which the aging effect is to be managed.

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

[Parameters Monitored or Inspected] The volume of water in the pond is the only parameter that is monitored. The Standby Nuclear Service Water Pond Volume Program requires a topographic survey of the ponds to determine the topography of the bottom of the SNSW pond. Calculations are then performed using the survey data to determine the volume of water within the SNSW pond. This is acceptable to the staff because this parameter provides an effective means of managing the aging effect of water depletion.

[Detection of Aging Effects] The applicant stated that no actions are taken as part of this program to detect aging effects, and the application is silent in regard to the remedial action that the applicant will take in case a future survey of the topography of the bottom of the pond indicates a reduction in the volume of water due to the buildup of sediment. By letter dated January 28, 2002, the staff requested, in RAI 4.7.3-1, that the applicant clarify this aspect of the SNSW pond volume program. In its response dated March 11, 2002, the applicant stated that, in the event that a future survey of the topography of the bottom of the SNSW pond indicates a reduction in the volume of water due to the buildup of sediment, remedial actions may include, but not be limited to the following:

- enlargement of the pond by excavation
- raising the required Technical Specification elevation
- dredging of the pond
- modification of the pond to raise the surface elevation

The staff finds these remedial actions acceptable because they provide an effective means of managing the aging effect due to sedimentation. With the closure of this RAI concern, the staff finds the detection of aging effects acceptable.

[Monitoring and Trending] The design parameter (volume of water within the SNSW pond) is validated using the SNSW Pond Volume Program. Conventional methods of surveying and volume calculation are used. A contour map with a known scale is developed as a result of the survey. Areas within each contour at different elevations are determined. Using the contour intervals and the area at each contour interval, volumes are computed for each contour elevation. The computed surface areas and the volume of water below the specified pond surface elevations at each contour elevation are compared to the areas and volumes in Figure 9-54 in the Catawba UFSAR to ensure that an adequate volume of water is available.

The SNSW Pond Volume Program is performed once every three years, and is documented and retained in sufficient detail to permit adequate confirmation of the results. The staff finds the monitoring and trending acceptable because the monitoring frequencies will permit an effective management of the aging effects, and because monitoring is performed by utilizing reliable and conventional surveying methods.

[Acceptance Criteria] The acceptance criteria are contained in the area-volume curve shown in Catawba UFSAR, Figure 9-54. Calculated areas and volumes are compared to the criteria in Figure 9-54. The staff finds the acceptance criteria to be adequate and acceptable because the applicant has used conservative and reasonable margins to estimate the volume of water in the SNSW pond.

[Operating Experience] The LRA states that previous surveys and calculations have verified that the surface area and volume of water in the SNSW pond is sufficient. The surveys were performed in accordance with plant procedures that implement the requirements of TS 5.4. The staff finds this approach acceptable because proven surveying methods were used to demonstrate that pond volume was sufficient.

4.7.3.3 FSAR Supplement

The changes to the Catawba UFSAR related to this TLAA are provided in the FSAR supplement in Appendix A-2 of the LRA. The staff reviewed the changes documented therein and finds them appropriate and acceptable.

4.7.3.4 Conclusions

On the basis of the review described above, the staff concludes that the applicant has demonstrated that the SNSW Pond Volume Program will adequately manage the aging effects associated with the SNSW pond so that there is reasonable assurance that it will continue to perform its intended function in accordance with the CLB for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii).

5. REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

The NRC staff issued its safety evaluation report (SER) with open items related to the renewal of operating licenses for McGuire, Units 1 and 2, and Catawba, Units 1 and 2, on August 14, 2002. On October 8, 2002, the applicant presented its license renewal application, and the staff presented its review findings, to the ACRS Plant License Renewal Subcommittee. The staff reviewed the applicant's responses to SER open and confirmatory items and completed its review of the license renewal application. The staff's evaluation is documented in an SER that was issued by letter dated January 6, 2003.

During the 499th meeting of the ACRS on February 5-7, 2003, the ACRS completed its review of the McGuire and Catawba license renewal application and the NRC staff's SER. The ACRS documented its findings in a letter to the Commission dated February 14, 2003. A copy of this letter is provided on the following pages of this SER Chapter.

ACRSR-2019

February 14, 2003

The Honorable Richard A. Meserve
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE MCGUIRE NUCLEAR STATION UNITS 1 AND 2 AND THE CATAWBA NUCLEAR STATION UNITS 1 AND 2

Dear Chairman Meserve:

During the 499th meeting of the Advisory Committee on Reactor Safeguards on February 6–8, 2003, we completed our review of the License Renewal Application (LRA) for the McGuire Nuclear Station Units 1 and 2 (McGuire) and the Catawba Nuclear Station Units 1 and 2 (Catawba), and the related final safety evaluation report (SER) prepared by the NRC staff. Our review included a meeting of our Plant License Renewal Subcommittee on October 8, 2002. During our review, we had the benefit of discussions with representatives of the NRC staff and Duke Energy Corporation (Duke). We also had the benefit of the documents referenced.

CONCLUSIONS AND RECOMMENDATIONS

1. The Duke application for renewal of the operating licenses for McGuire Units 1 and 2 and Catawba Units 1 and 2 should be approved.

2. The programs instituted to manage aging-related degradation are appropriate and provide reasonable assurance that McGuire Units 1 and 2 and Catawba Units 1 and 2 can be operated in accordance with their current licensing bases for the period of extended operation without undue risk to the health and safety of the public.

BACKGROUND AND DISCUSSION

This report fulfills the requirement of 10 CFR 54.25, which states that the ACRS should review and report on all license renewal applications. McGuire Units 1 and 2 and Catawba Units 1 and 2 are 3,411- MWt, four-loop Westinghouse pressurized-water reactors (PWRs) in ice condenser containments. In its application, Duke requested that the NRC renew the operating licenses for all four units beyond their current license terms, which expire on June 12, 2021 (McGuire Unit 1); March 3, 2023 (McGuire Unit 2); December 6, 2024 (Catawba Unit 1); and February 24, 2026 (Catawba Unit 2). At the time of the application, only McGuire Unit 1 met the requirements of 10 CFR 54.17(c), which prohibits an applicant from submitting an application for license renewal earlier than 20 years before the expiration of its current operating license. Duke requested an exemption from this requirement, which the NRC staff granted based on the similarities of the four units and the efficiency of a single application.

The final SER documents the results of the staff's review of information submitted by Duke, including commitments that were necessary to resolve open items identified by the staff in the initial SER. In particular, the staff reviewed the completeness of the applicant's identification of structures, systems, and components (SSCs) that are subject to aging management; the integrated plant assessment process; the applicant's identification of the possible aging mechanisms associated with passive, long-lived components; and the adequacy of the applicant's aging management programs. The staff also conducted several inspections at Duke's engineering offices and at the McGuire and Catawba sites to verify the adequacy of the methodology described in the application and its implementation.

During our Plant License Renewal Subcommittee meeting on October 8, 2002, the lead NRC license renewal inspector for Region II provided an overview of the NRC's inspection process. This process, which is well-structured and effective, is becoming increasingly important as license renewal applications become less detailed. As a result, as in other recent applications, the review of the McGuire and Catawba LRA required a substantial number of requests for additional information and depended heavily on review of plant drawings at the sites.

On the basis of our review of the final SER, we agree with the staff's conclusion that all open and confirmatory items have been closed appropriately, and there are no issues that preclude renewal of the operating licenses for McGuire Units 1 and 2 and Catawba Units 1 and 2.

The process implemented by the applicant to identify SSCs that are within the scope of license renewal was effective. However, in the initial SER the staff identified a number of SSCs that should have been in the scope of license renewal but were excluded by Duke's interpretation of license renewal requirements. Among those SSCs were fan and damper housings, building sealants, electrical equipment connecting the units to the offsite power source for recovery from station blackout (SBO), and jockey pumps and manual fire suppression equipment in potential fire exposure areas. The inclusion of fan and damper housings, building sealants, and SBO equipment has been disputed in previous license renewal applications.

For fan and damper housings, Duke initially took the position that loss of pressure retention or structural integrity function would be evidenced by functional failure, as is a failure of the active components of dampers and fans. By contrast, the staff views the passive components of these assemblies as being within the scope of license renewal, just like pump casings, which are explicitly called for in 10 CFR 54.21. We agree that the explicit example provided in the rule supports the staff's interpretation. With regard to jockey pumps, the staff determined that these components are relied upon to meet the requirements of 10 CFR 50.48, "Fire Protection." We concur with the staff's determination. Duke agreed to close these open items by bringing all of the identified SSCs into the scope of license renewal.

During our review, we questioned why certain other SSCs were not included within the scope and, in all cases, the applicant provided appropriate justification for exclusion. We conclude that the applicant and the staff have appropriately identified all SSCs that are within the scope of license renewal.

The applicant performed a comprehensive aging management review of SSCs that are within the scope of license renewal. Appendix B to the LRA describes 51 aging management programs for license renewal, which include existing, enhanced, and new programs. In addition, the resolution of staff questions and SER open items has resulted in further commitments, including the implementation of a one-time inspection of the condenser circulating water system expansion joints at Catawba to characterize potential degradation, one-time VT-1 inspection of the pressurizer spray head, one-time inspection of the internal surfaces of the auxiliary feedwater system carbon steel piping components, and an inspection program for non-environmentally qualified neutron flux instrumentation circuits. The SER lists 21 such committed actions to be implemented by the applicant.

The McGuire and Catawba LRA includes a new aging management program, the Alloy 600 Aging Management Review. This program is intended to identify Alloy 600/690, 82/182, and 52/152 locations; to rank susceptibility to primary water stress corrosion cracking (PWSCC); and to verify that nickel-based alloy locations are adequately inspected by the Inservice Inspection Program, the Control Rod Drive Mechanism and other Vessel Head Penetration (VHP) programs, the Reactor Vessel Internals Program, and the Steam Generator Integrity Program. This review will provide general oversight and management of cracking due to PWSCC. We applaud this initiative to provide comprehensive oversight of activities to manage PWSCC. Given the current challenge created by PWSCC, we encourage Duke to implement this program soon, in the current license term, rather than waiting for the end of the initial license terms of the four units.

With regard to reactor vessel penetration nozzle cracking and head wastage issues, Duke has committed to incorporate the future industry resolution of these issues into the VHP Nozzle Program and the Alloy 600 Management Review Program. This provides reasonable assurance that the effects of aging associated with the VHP Nozzle Program and the Alloy 600 Review Program will be adequately managed so that the intended function(s) will be maintained in a manner that is consistent with the current licensing basis throughout the period of extended operation.

Duke is the first utility to seek license renewal for plants that use ice condensers in the containment to absorb thermal energy in the event of a loss-of-coolant-accident or a steamline break. Duke has developed a new program to manage aging degradation of ice baskets and ice condenser components at McGuire and Catawba. We agree with the staff's conclusion that the proposed program is adequate to identify and manage aging effects during the period of extended operation.

Duke identified those components of the McGuire and Catawba plants that are supported by time-limited aging analyses and provided sufficient data to demonstrate that the components have sufficient margin to operate properly for the period of extended operation.

As noted in previous applications, LRAs include a substantial number of activities and commitments that will not be accomplished until near the end of the current license period. Consequently, the NRC staff will need to conduct a substantial amount of inspection activity just before the plants enter the extended period of operation. The staff is aware of this future workload and has issued Inspection Procedure 71003, "Post-Approval Site Inspection for License Renewal," to manage this significant effort. Given the large number of power plants that will approach the license renewal term at approximately the same time, this nationwide inspection effort is likely to impose a major demand for staff resources.

The staff has performed an outstanding review of the Duke application. The applicant and the staff have identified plausible aging effects associated with passive, long-lived components. The applicant has also established adequate programs to manage the effects of aging so that McGuire Units 1 and 2 and Catawba Units 1 and 2 can be operated in accordance with their current licensing bases for the period of extended operation without undue risk to the health and safety of the public.

Sincerely,

/RA/

Mario V. Bonaca
Chairman

References:

1. Letter dated June 13, 2001, from M. S. Tuckman, Duke Energy Corporation, to U. S. Nuclear Regulatory Commission, transmitting Application to Renew the Operating Licenses of McGuire Nuclear Station, Units 1 and 2 and Catawba Nuclear Station, Units 1 and 2.
2. U.S. Nuclear Regulatory Commission, NUREG-XXX, "Safety Evaluation Report Related to the License Renewal of McGuire Nuclear Station, Units 1 and 2 and Catawba Nuclear Station, Units 1 and 2," January 2003.
3. U.S. Nuclear Regulatory Commission, NRC Inspection Procedure 71003, "Post-Approval Site Inspection for License Renewal," December 9, 2002.

6. CONCLUSIONS

The staff performed its review of the McGuire and Catawba license renewal application in accordance with Federal regulations and the NRC's "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," issued July 2001. The standards for issuance of a renewed license are provided in 10 CFR 54.29.

On the basis of its evaluation of the application as discussed above, the staff has determined that it will be able to conclude that the requirements of 10 CFR 54.29(a) have been met.

The staff notes that any requirements of Subpart A of 10 CFR Part 51 will be documented in the plant-specific supplement to the Generic Environmental Impact Statement. Should the resolution of Subpart A of 10 CFR Part 51 be favorable, the staff will be able to conclude that the requirements of 10 CFR 54.29(b) have been met.

At this time, no matters have been raised under 10 CFR 2.758 that need to be addressed. The staff reserves judgment regarding the requirements of 10 CFR 54.29(c) until such time that it can determine if matters have been raised under 10 CFR 2.758.

APPENDIX A
CHRONOLOGY

This appendix contains a chronological listing of routine licensing correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke Energy Corporation (Duke). This appendix also contains other correspondence regarding the NRC staff's review of the McGuire Nuclear Station, Units 1 and 2, (under docket Nos. 50-369 and 50-370), and Catawba Nuclear Station, Units 1 and 2, (under docket Nos. 50-413 and 50-414).

May 8, 2001	In a letter (signed by S. Hoffman), the NRC issued a notice for a public meeting on May 21, 2001. In this meeting, Duke planned to discuss schedules for planned license renewals for McGuire and Catawba Nuclear Stations. ACN: ML011290008
June 5, 2001	In a letter (signed by C. Araguas), the NRC issued a notice for a public meeting on June 20, 2001, between the NRC, Duke, Virginia Electric Power Company (VEPCo), and Exelon. In this meeting, the licensees planned to continue discussions from a prior meeting on May 21, 2001, on the review schedules for their planned license renewal application. ACN: ML011560744
June 6, 2001	In a letter (signed by S. Hoffman), the NRC published a summary of a public meeting that was held on May 21, 2001, between the NRC, Duke, VEPCo, and Exelon regarding the review schedules for their planned license renewal application. ACN: ML011590263
June 7, 2001	In a letter (signed by R. Prato), the summary of a telecommunication between the NRC, VEPCo, and Duke was published and documented. The telecommunication was held on June 6, 2001. Duke discussed an integrated inspection schedule for the license renewal inspection activities planned for McGuire and Catawba Nuclear Stations. ACN: ML011590499
June 13, 2001	In a letter (signed by M.S. Tuckman), Duke submitted its form and content of License Renewal Application (LRA) and Appendices for McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML011660301
June 13, 2001	In a letter (signed by M.S. Tuckman), Duke submitted its intent to apply for renewal of the operating licenses of McGuire and Catawba power stations. In its submittal, Duke provided fourteen copies of the application. ACN: ML011660138
June 13, 2001	In a letter (signed by M.S. Tuckman), Duke submitted two sets of marked flow drawings to aid the NRC in its review of *Application to Renew the Operating Licenses of McGuire Nuclear Station, Units 1 and 2 and Catawba Nuclear Station, Units 1 and 2*. ACN: ML011660168

June 28, 2001	In a letter (signed by M.S. Tuckman), Duke submitted its application to renew the operating licenses of McGuire and Catawba power stations. In its submittal, Duke provided one hard copy of the application and 40 copies of the application on CD ROM. ACN: ML011840032
June 28, 2001	In a letter (signed by R. Franovich), the NRC issued a notice for a public meeting on July 12, 2001. In this meeting, Duke planned to provide the NRC staff with a review of the license renewal application for McGuire and Catawba Nuclear Stations, and to clarify the organization of the license renewal application. ACN: ML011800037
July 10, 2001	In a letter (signed by R. Franovich), the NRC published a summary of a public meeting that was held on June 20, 2001, between the NRC, Duke, VEPCo, and Exelon. This meeting was held to continue discussions from the prior meeting on May 21, 2001, on the review schedules for their planned license renewal applications. ACN: L011930405
July 24, 2001	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on July 19, 2001, to clarify technical information provided by Duke in LRA Table 3.2-4. ACN: ML012070063
July 26, 2001	In a letter (signed by R. Franovich), the NRC published a summary of a public meeting that was held on July 12, 2001, between the NRC and Duke to provide an orientation for the staff on the McGuire and Catawba LRA. ACN: ML012080051
August 31, 2001	In a letter (signed by S. Hoffman), the NRC issued a notice for a public meeting on September 19, 2001, between the NRC, the Nuclear Energy Institute (the NEI), Southern Nuclear Oporation Company (SNC), Hatch Nuclear Plant, Units 1 and 2 (HNP), Florida Power and Light Company (FPL), Duke, VEPCo, and Exelon. In this meeting, the licensees planned to discuss the review status of their LRAs. ACN: ML012430275
September 10, 2001	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on August 21, 2001, to clarify information provided by Duke on the Boraflex Monitoring Program in LRA Appendix B. ACN: ML012530283
October 3, 2001	In a letter (signed by R. Franovich), the NRC issued a notice for a public meeting on October 18, 2001, between the NRC and Duke to discuss a scoping methodology audit in support of license renewal application review for McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML012770008

October 10, 2001	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on September 12, 2001, to clarify information provided by Duke in its LRA on several waste treatment and disposal systems. ACN: ML012830102
October 15, 2001	In a letter (signed by R. Franovich), the summary of two telecommunications between the staff and Duke was published and documented. These telecommunications were held on September 18 and 20, 2001, to clarify information provided by Duke in its McGuire and Catawba LRA regarding scoping of structures and components in the fire protection systems. ACN: ML012880370
October 21, 2001	In a letter (signed by S. Hoffman), the NRC issued a summary of a public meeting that was held on September 19, 2001, between the NRC, the NEI, SNC, FPL, VEPCo, Duke, and Exelon regarding the status of license renewal activities. ACN: ML012840369
November 2, 2001	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on October 3, 2001, to clarify information provided by Duke in its McGuire and Catawba LRA regarding scoping of structures and components in the fire protection systems. ACN: ML013060438
November 14, 2001	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on October 11, 2001, to clarify information provided by Duke in its McGuire and Catawba LRA regarding containment systems. ACN: ML013190029
November 14, 2001	In a letter (signed by C. Grimes), the NRC provided the NEI, the Union of Concerned Scientists (the UCS), and current license renewal applicants with their proposed staff guidance on station blackout scoping for comments. ACN: ML013180508
November 15, 2001	In a letter (signed by R. Franovich), the NRC issued a summary of a public exit meeting that was held on October 19, 2001, between the NRC and Duke regarding the scoping methodology audit in support of license renewal application review for McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML013190507
November 23, 2001	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on October 11, 2001, to clarify information presented in the LRA pertaining to aging management programs for structures. ACN: ML013310117

November 23, 2001	In a letter (signed by C. Grimes), the NRC provided the NEI, the UCS, and current license renewal applicants with proposed changes to the "Generic Aging Lessons Learned" (GALL) report for comments on the aging management of concrete. ACN: ML013300426
November 23, 2001	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on October 15, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Appendix B, Inservice Inspection Plan. ACN: ML013300361
November 30, 2001	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on October 25, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Section 3.5. ACN: ML013370544
November 30, 2001	In a letter (signed by R. Prato), the NRC issued a notice for a public meeting on December 12, 2001, between the NRC, VEPCo, Duke, Exelon, and the NEI to discuss license renewal emerging issues. ACN: ML013370001
December 3, 2001	In a letter (signed by C. Grimes), the NRC provided the NEI, the UCS, and current license renewal applicants with the staff's characterization of the license renewal issue pertaining to scoping of seismic II/I piping for comments. ACN: ML013380013
December 11, 2001	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on October 30, 2001, to clarify information presented in the LRA pertaining to aging management programs for mechanical systems and components. ACN: ML013460154
December 11, 2001	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on November 8, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Section B.3.12, Fire Protection Program. ACN: ML013460269
December 12, 2001	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on October 25, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Appendix B. ACN: ML013460417

December 13, 2001	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on November 5, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Appendix B, on aging management programs for mechanical systems and components. ACN: ML013470364
December 14, 2001	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on December 3, 2001, to clarify information presented by Duke on its McGuire and Catawba LRA, Section B.3.6. ACN: ML013520129
December 14, 2001	In a letter (signed by S. Hoffman), the NRC issued a notice for a public meeting on January 8, 2002, between the NRC, SNC, FPL, VEPCo, Duke, and Exelon to discuss the review status and other activities associated with LRAs. ACN: ML013510294
December 18, 2001	In a letter (signed by R. Prato), the NRC issued a notice for a public meeting on January 10, 2002, between the NRC, VEPCo, Duke, Exelon, and the NEI to discuss license renewal station blackout issues. ACN: ML013600335
December 27, 2001	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on November 13, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Sections 2.5, 3.6, and B.3.19. ACN: ML013650428
January 10, 2002	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on November 20, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Section 4.6. ACN: ML020110099
January 11, 2002	In a letter (signed by D. Solorio), the NRC issued a notice for a public meeting on January 15, 2002, during which the NEI and current license renewal applicants planned to follow up on the January 10, 2002, meeting regarding the license renewal station blackout issue. ACN: ML020110589
January 15, 2002	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on November 28, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Sections 2.3.2 and 2.3.3. ACN: ML020170132

January 15, 2002	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on November 27, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Sections 2.3.4, 2.3.3.27, 2.3.3.34, and 2.3.3.36. ACN: ML020160418
January 17, 2002	In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Sections 2.5, 3.6, and B.3.19 of the McGuire and Catawba LRA. ACN: ML020180061
January 17, 2002	In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Sections 2.1 and B.2 of the McGuire and Catawba LRA. ACN: ML020220034
January 17, 2002	In a letter (signed by P. Kang), the NRC issued a notice for a public meeting on February 14, 2002, between the NRC, the NEI, and current license renewal applicants to discuss revised sections of Chapters II and III of the GALL report on aging management of concrete elements. ACN: ML020220005
January 17, 2002	In a letter (signed by R. Prato), the NRC issued a summary of a public meeting that was held on December 12, 2001, between the NRC, VEPCo, Duke, Exelon, and the NEI regarding license renewal emerging issues. ACN: ML020300004
January 22, 2002	In a letter (signed by R. Prato), the NRC published a summary of a public meeting that was held on January 10, 2002, between the NRC, VEPCo, Duke, Exelon, the NEI, and the Nuclear Information and Resource Service regarding the scope of station blackout specific to license renewal. ACN: ML020220351
January 23, 2002	In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Section 2.2 of the McGuire and Catawba LRA. ACN: ML020290102
January 23, 2002	In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Section 2.3.2 of the McGuire and Catawba LRA. ACN: ML020240249
January 24, 2002	In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Section 3.3 of the McGuire and Catawba LRA. ACN: ML020240265
January 28, 2002	In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Section 2.3.3 of the McGuire and Catawba LRA. ACN: ML020320212

January 28, 2002	In a letter (signed by C. Grimes), the NRC provided the NEI, the UCS, and current license renewal applicants with their proposed guidance on aging management of fire protection systems comments. ACN: ML020320437
January 28, 2002	In a letter (signed by C. Grimes), the NRC requested comments from the NEI, the UCS, and current license renewal applicants on the revised proposed guidance on station blackout scoping. ACN: ML020300294
January 28, 2002	In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Section 3.2 of the McGuire and Catawba LRA. ACN: ML020320010
January 28, 2002	In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Appendix B, Aging Management Programs (Mechanical Systems), of the McGuire and Catawba LRA. ACN: ML020310200
January 28, 2002	In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Sections 2.3.1, 3.1, 4.2, 4.3, 4.7.1, and Appendix B of the McGuire and Catawba LRA. ACN: ML020310255
January 28, 2002	In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Sections 2.4, 3.5, 4.6, 4.7.3, and Appendix B of the McGuire and Catawba LRA. ACN: ML020320165
January 30, 2002	In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Section 3.1 and Appendix B, Section B.3.27 of the McGuire and Catawba LRA. ACN: ML020350542
January 31, 2002	In a letter (signed by P. Kang), the NRC issued a notice for a public meeting on February 14, 2002, between the NRC, the NEI, and current license renewal applicants in order to discuss station blackout issues related to license renewal. This meeting follows discussions initiated in a public meeting held on January 10 and 15, 2002. ACN: ML020320079
February 5, 2002	In a letter (signed by P. Kang), the NRC published a summary of a public meeting that was held on January 15, 2002, between the NRC, the NEI, and current license renewal applicants. This meeting was held to continue the discussion that began with the January 10, 2002, meeting on station blackout issues related to license renewal. ACN: ML020380195
February 11, 2002	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on January 9, 2002, to clarify information presented by Duke in its McGuire and Catawba LRA, Sections 3.1, B.3.1, B.3.26, B.3.27, B.3.31, and 4.2.1. ACN: ML020420453

February 13, 2002	In a letter (signed by D. Solorio), the NRC published a notice for a public meeting on February 25, 2002, between the NRC, the NEI, and current license renewal applicants to discuss implementation details of the license renewal interim staff guidance process. ACN: ML020460082
February 21, 2002	In a letter (signed by S. Hoffman), the NRC published a summary of a public meeting that was held on January 8, 2002, between the NRC, SNC, FPL, VEPCo, Duke, and Exelon regarding the progress of license renewal application reviews. ACN: ML020560022
March 1, 2002	In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's RAIs dated January 17 and 23, 2002, regarding the scoping and screening methodology of the McGuire and Catawba LRA. ACN: ML020640428
March 1, 2002	In a letter (signed by M.S. Tuckman), Duke responded to RAIs on scoping and screening methodology and plant level scoping results. ACN: ML020640428
March 1, 2002	In a letter (signed by C. Grimes), the NRC requested comments from the NEI, the UCS, and current license renewal applicants on the revised proposed guidance on station blackout scoping. ACN: ML020600100
March 6, 2002	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on February 21, 2002, to clarify information presented by Duke in its McGuire and Catawba LRA, Section 2.4.2. ACN: ML020660073
March 7, 2002	In a letter (signed by P. Kang), the NRC published a summary of a public meeting that was held on February 14, 2002, between the NRC, the NEI, and current license renewal applicants regarding revised guidance on station blackout scoping. ACN: ML020700212
March 8, 2002	In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's RAIs dated January 17, 2002, regarding Sections 2.5, 3.6, and Appendix B Section B.3.19 of the McGuire and Catawba LRA. ACN: ML020740025
March 11, 2002	In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's RAIs dated January 28, 2002, regarding Sections 2.4, 3.5, 4.6, 4.7.3, and Appendix B of the McGuire and Catawba LRA. ACN: ML020770266
March 13, 2002	In a letter (signed by S. Hoffman), the NRC published a notice for a public meeting on April 8, 2002, between the NRC, the NEI, and current license renewal applicants to discuss the status of the renewal applications and generic license renewal activities. ACN: ML020720270

March 15, 2002	In a letter (signed by K. S. Canady), Duke submitted its response to the NRC staff's RAIs dated January 23 and 28, 2002, regarding aging management review of auxiliary systems and of engineered safety features, including aging management programs for mechanical systems for McGuire and Catawba LRA. ACN: ML020810451
March 15, 2002	In a letter (signed by C. Grimes), the NRC requested comments from the NEI, the UCS, and current license renewal applicants on the license renewal issue guidance pertaining to 10 CFR 54.4 (a)(2) Scoping. ACN: ML020770026
March 22, 2002	In a letter (signed by P. Kang), the NRC published a notice for a public meeting on April 10, 2002, between the NRC, the NEI, and current license renewal applicants to discuss revised sections of Chapters II and III of the GALL report on the aging management of concrete elements and other currently emerging issues related to license renewal. ACN: ML020840411
March 22, 2002	In a letter (signed by P. Kang), the NRC published a notice for a public meeting on April 10, 2002, between the NRC, the NEI, and current license renewal applicants to discuss the staff proposed guidance for aging management of fire protection systems in the GALL report. ACN: ML020840444
April 1, 2002	In a letter (signed by D. Matthews), the NRC submitted a copy of the revised staff position on scoping station blackout equipment for license renewal and clarified the use of alternate ac power sources. ACN: ML020920464
April 4, 2002	In a letter (signed by P. Kang), the NRC published a summary of a public meeting that was held on February 14, 2002, between the NRC, the NEI, and current license renewal applicants regarding revisions to GALL Chapters II and III. ACN: ML020940312
April 5, 2002	In a letter (signed by C. Grimes), the NRC informed the NEI and current license renewal applicants of its "Staff's Response to Industry's Proposed Changes to GALL Chapters II and III on Aging Management of Concrete Elements." ACN: ML020980194
April 15, 2002	In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's RAIs dated January 23 and 28, 2002, and March 1, 8, and 15, 2002, regarding Sections 2.1-2a, 2.1-2b, 2.3.1, 2.3.2, 2.3.3, 3.1, 3.2-1, 3.3-1, 3.3-2, 4.2, 4.3, 4.7.1, B.3.19-1, B.3.19-2, and several sections of Appendix B of the McGuire and Catawba LRA. ACN: ML021120015
April 22, 2002	In a letter (signed by P. Kang), the NRC published a summary of a public meeting that was held on April 10, 2002, between the NRC, the NEI, and current license renewal applicants regarding staff guidance on license renewal issues. ACN: ML021120407

April 22, 2002	In a letter (signed by N. Dudley), the NRC published a summary of a public meeting that was held on April 8, 2002, between the NRC, Omaha Public Power District (OPPD), FPL, VEPCo, Duke, and Exelon regarding the progress of license renewal application reviews. ACN: ML021130114
May 5, 2002	In a letter (signed by V. McCree), the NRC sent Duke its scoping and screening inspection report. ACN: ML021280003
June 7, 2002	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on May 24, 2002, to clarify information provided by Duke in LRA Section 2.1. ACN: ML021620457
June 7, 2002	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on May 28, 2002, to clarify information provided by Duke in LRA Section 3.5. ACN: ML021700648
June 19, 2002	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on June 5, 2002, to clarify information provided by Duke in LRA Section B.3.26. ACN: ML021700621
June 19, 2002	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on June 4, 2002, to clarify information provided by Duke in LRA Section 4.3. ACN: ML021750433
June 24, 2002	In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on May 29, 2002, to clarify information provided by Duke in LRA Sections 3.6 and B.3.19. ACN: ML021620496
June 25, 2002	In a letter (signed by M.S. Tuckman), Duke submitted Amendment I to the application to renew the facility operating licenses of McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML021840126
June 25, 2002	In a letter (signed by M.S. Tuckman), Duke submitted drawing MCFD-01-01 which is part of Amendment I to the application to renew the facility operating licenses of McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML021920158
June 26, 2002	In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's RAIs dated January 17, 2002, regarding Sections 2.5-1 and 2.5-2 of the McGuire and Catawba LRA. ACN: ML021840103

June 26, 2002	In a letter (signed by R. Franovich), the NRC provided Duke potential safety evaluation report open items regarding the license renewal application for McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML021770454
July 9, 2002	In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's letter dated June 26, 2002, regarding 29 potential open items and 10 confirmatory items identified during the staff's preparation of its safety evaluation report on the McGuire and Catawba LRA. ACN: ML021960467
August 14, 2002	In a letter (signed by P. T. Kuo), the NRC issued its safety evaluation report with open items, which documented the staff's initial review of the license renewal application for McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML022260949
August 29, 2002	In a letter (signed by R. Franovich), the NRC provided Duke a revised schedule for the review of the license renewal application for McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML022410304
September 4, 2002	In a letter (signed by R. Franovich), the NRC issued a notice for a public meeting on September 17-19, 2002, between the NRC and Duke. In this meeting the staff and applicant planned to discuss open and confirmatory items identified in the SER issued August 14, 2002. ACN: ML022470378
September 6, 2002	In a letter (signed by R. Franovich), the NRC issued a notice for a public meeting on October 1, 2002, between the NRC and Duke. In this meeting the staff and applicant planned to discuss open items pertaining to scoping and screening of fire protection equipment that were identified in the SER issued August 14, 2002. ACN: ML022520227
September 9, 2002	In a letter (signed by L. Plisco for V. McCree), the NRC sent Duke its aging management review inspection report. ACN: ML022540009
September 12, 2002	In a letter (signed by R. Franovich), the NRC issued a notice for a public meeting on October 1, 2002, between the NRC and Duke. In this meeting the staff and applicant planned to discuss open items pertaining to scoping and screening of fire protection equipment that were identified in the SER issued August 14, 2002. ACN: ML022560227
September 13, 2002	In a letter (signed by R. Franovich), the NRC issued a request of revised time-limited aging analyses associated with reactor vessel neutron embrittlement for the staff's review of the license renewal application for McGuire 1. ACN:ML022590100

October 2, 2002	In a letter (signed by M.S. Tuckman), Duke submitted its interim response to the NRC staff's safety evaluation report with open items issued August 14, 2002, on the McGuire and Catawba LRA. ACN:ML022830191
October 19, 2002	In a letter (signed by R. Franovich), the NRC issued a revised excerpt from the safety evaluation report with open items and request for additional information to complete the staff's review of the McGuire and Catawba LRA. ACN:ML022940260
October 28, 2002	In a letter (signed by M.S. Tuckman), Duke submitted its second response to the NRC staff's safety evaluation report with open items issued August 14, 2002, on the McGuire and Catawba LRA. ACN:ML023090324
November 5, 2002	In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's letter dated October 19, 2002, regarding a revised excerpt from the safety evaluation report with open items and request for additional information to complete the staff's review of the McGuire and Catawba LRA. ACN:ML023180047
November 7, 2002	In a letter (signed by R. Franovich), the NRC requested the applicant to address its treatment of fuse holders within the scope of license renewal as long-lived, passive components subject to an aging management review in the McGuire and Catawba LRA. ACN:ML023120413
November 13, 2002	In a letter (signed by P.T. Kuo), the NRC apprized the applicant of the status of the NRC staff's review of the McGuire and Catawba LRA and safety evaluation report open items that remained unresolved. ACN:ML023170631
November 14, 2002	In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's letter dated November 13, 2002, regarding safety evaluation report open items that remained unresolved. ACN:ML023300321
November 18, 2002	In a letter (signed by M.S. Tuckman), Duke submitted a supplemental response to the NRC staff's letter dated November 13, 2002, regarding safety evaluation report open items that remained unresolved. ACN:ML023300288
November 18, 2002	In a letter (signed by R. Franovich), the NRC issued a summary of the public meetings held September 17-19, 2002, between the NRC and Duke. In this meeting the staff and applicant discussed open and confirmatory items identified in the SER issued August 14, 2002. ACN: ML023220127

November 21, 2002	In a letter (signed by M.S. Tuckman), Duke submitted a third response to the NRC staff's letter dated November 13, 2002, regarding safety evaluation report open items that remained unresolved. ACN: ML023180047
November 26, 2002	In a letter (signed by R. Franovich), the NRC issued a summary of the public meeting held October 1, 2002, between the NRC and Duke. In this meeting the staff and applicant discussed open items pertaining to scoping and screening of fire protection equipment that were identified in the SER issued August 14, 2002. ACN: ML023330429
December 16, 2002	In a letter (signed by M.S. Tuckman), Duke submitted revised FSAR supplements and a table of license renewal commitments. ACN: ML023540450
January 6, 2003	In a letter (signed by P. T. Kuo), the NRC issued its safety evaluation report related to the license renewal of McGuire, Units 1 and 2, and Catawba, Units 1 and 2. ACN: ML023640366
February 14, 2003	In a letter (signed by M. Bonaca), the Advisory Committee on Reactor Safeguards provided its conclusions and recommendations on the renewal of the operating licenses for McGuire, Units 1 and 2, and Catawba, Units 1 and 2. ACN: ML030450549

APPENDIX B
REFERENCES

This appendix contains a listing of references used in the preparation of the Safety Evaluation Report prepared during the review of the license renewal application for McGuire 1 and 2, Docket Numbers 50-369 and 50-370, and Catawba 1 and 2, Docket Numbers 50-413 and 50-414.

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Duke Energy Corporation

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APPENDIX C
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E. Barnhill	Administrative Support
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W. Bateman	Management Supervision
L. Bell	Administrative Support
S. Black	Management Supervision
B. Boger	Management Supervision
W. Burton	Technical Support
J. Calvo	Management Supervision
R. Caruso	Management Supervision
C. Casto	Management Supervision
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S. Coffin	Management Supervision
B. Crowley	Region II Inspector
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W. Dean	Management Supervision
C. Dorsey	Administrative Support
N. Dudley	Technical Support
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Pacific Northwest National Laboratory	Aging Management Reviews

APPENDIX D
LIST OF APPLICANT COMMITMENTS

McGuire Nuclear Station
List of Committed Actions to be Implemented for License Renewal

Item	Commitment	UFSAR Section	Implementation Schedule	Source
1.	(a) Complete the Alloy 600 Aging Management review. (b) Submit the results of the review for the pressurizer surge and spray nozzle thermal sleeve attachment welds. (c) The summary aging management program descriptions contained in this UFSAR will be updated as necessary to reflect any new or revised commitments made by Duke in response to the staff generic communications that results from the Davis-Besse event in March 2002. (d) The results of this review will be incorporated into the unit specific inservice inspection (ISI) plan for the ISI intervals during the period of extended operation.	18.2.1	(a) Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. (b) Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. (c) As necessary (d) Prior to the respective ISI interval	Application B.3.1; Duke letters dated 10/28/2002 (response to New Open Item 3.1.3.2.2-2) and 11/21/2002 (Item 3)
2.	Complete the Borated Water Systems Stainless Steel Inspection.	18.2.2	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Application B.3.4

McGuire Nuclear Station
List of Committed Actions to be Implemented for License Renewal

Item	Commitment	UFSAR Section	Implementation Schedule	Source
3.	(a) Implement the Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetrations Inspection Program. (b) Update UFSAR summary description of this program to reflect any new or revised commitments made by Duke in response to the staff generic communications that result from the Davis-Besse event in March 2002.	18.2.6	(a) Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. (b) As necessary	Application B.3.9; Duke letter dated 10/28/2002 (response to New Open Item 3.1.3.2.2-2)
4.	Implement enhancements to the Fire Protection Program to provide surveillances for sprinkler branch lines, main fire pump strainer, jockey pump strainer, tank and connected piping, and turbine building manual hose stations.	18.2.8	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Application B.3.12; Duke letters dated 03/15/2002 (Commitment #8), 10/28/2002 (response to Open Items 2.3.3.19-2 & 2.3.3.19-5), and 11/18/2002 response to (Open Item 2.3.3.19-4)
5.	Complete the Galvanic Susceptibility Inspection.	18.2.12	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Application B.3.16; Duke letter dated 03/15/2002 (Commitment #10)

McGuire Nuclear Station
List of Committed Actions to be Implemented for License Renewal

Item	Commitment	UFSAR Section	Implementation Schedule	Source
6.	Implement enhancements to the Heat Exchanger Preventive Maintenance Activities to provide surveillances for pump motor air handling units and pump oil coolers.	18.2.13	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Application B.3.17; Duke letter dated 10/28/2002 (Duke identified Mechanical Item 09/18/2002)
7.	Implement the Inaccessible Non-EQ Medium Voltage Cables Aging Management Program.	18.2.15	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Application B.3.19; Duke letters dated 10/02/2002 (Confirmatory Item 3.6.2-1) and 11/05/2002 (Attachment 1)
8.	Implement enhancements to the Inservice Inspection Plan to provide surveillances for the Unit 1 cold leg elbow and small bore piping.	18.2.16	Evaluation of the Unit 1 cold leg elbow will be completed following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. Small bore piping examinations will be performed during each inservice inspection interval during the period of extended operation following issuance of the renewed operating licenses for McGuire.	Application B.3.20; Duke letters dated 04/15/2002 (Commitment #1) and 11/14/2002 (response to New Open Item 3.0.3.10.2-1)

McGuire Nuclear Station
List of Committed Actions to be Implemented for License Renewal

Item	Commitment	UFSAR Section	Implementation Schedule	Source
9.	Implement enhancements to the Inspection Program for Civil Engineering Structures and Components to provide surveillances for exposed external surfaces of mechanical components.	18.2.17	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Application B.3.21; Duke letter dated 10/02/2002 (response to Open Item 3.0.3.11.3-1)
10.	Complete the Liquid Waste System Inspection.	18.2.18	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Application B.3.22
11.	Complete the future modification to the Thermal Fatigue Management Program for environmentally assisted fatigue.	5.2.1	Prior to the end of the 40th year of each unit's operation.	Application 4.3; Duke letter dated 10/02/2002 (response to Open Item 4.3-4)
12.	Implement the Non-EQ Insulated Cables and Connections Aging Management Program.	18.2.19	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Application B.3.23; Duke letter dated 10/02/2002 (response to SER Confirmatory Item 3.6.1.1)
13.	(a) Complete the Pressurizer Spray Head Examination on McGuire Unit 1. (b) If necessary, complete the Pressurizer Spray Head Examination on Unit 2.	18.2.20	(a) Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. (b) Following issuance of the renewed operating licenses for McGuire Nuclear Station and by March 3, 2023.	Duke letters dated 04/15/2002 (response to RAI 2.3.2.7-1) and 10/28/2002 (response to Open Item 3.1.2.2.2-1)

McGuire Nuclear Station
List of Committed Actions to be Implemented for License Renewal

Item	Commitment	UFSAR Section	Implementation Schedule	Source
14.	(a) Implement the Reactor Vessel Internals Inspection. (b) For items comprised of plates, forgings, and welds critical crack size will be determined by analysis and submitted for review and approval to the NRC. (c) For items fabricated from CASS, critical crack size will be determined by analysis. Acceptance criteria for all aging effects will be developed and submitted for review and approval to the NRC.	18.2.23	(a) McGuire Unit 1 will be inspected in the fifth inservice inspection interval; McGuire Unit 2 will be inspected early in the sixth inservice inspection interval. (b) Prior to the respective inspection. (c) Prior to the respective inspection.	Application B.3.27; Duke letter dated 10/28/2002 (response to New Open Items 3.1.4-1(a), (b), and (c))
15.	Complete the Selective Leaching Inspection.	18.2.24	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Application B.3.28
16.	Complete the Sump Pump Systems Inspection.	18.2.26	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Application B.3.32
17.	Complete the Treated Water Systems Stainless Steel Inspection.	18.2.27	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Application B.3.34

McGuire Nuclear Station
List of Committed Actions to be Implemented for License Renewal

Item	Commitment	UFSAR Section	Implementation Schedule	Source
18.	Complete the Ventilation Area Pressure Boundary Sealants Inspection.	18.2.29	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Duke letters dated 10/28/2002 (response to Open Item 2.3-3) and 11/14/2002 (response to Open Item 2.3-3)
19.	Complete the Waste Gas System Inspection.	18.2.30	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Application B.3.36
20.	Complete the visual inspections of the interior surfaces of Auxiliary Feedwater System and Main Feedwater System components.	18.3.3	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Duke letter dated 10/28/2002 (response to New Open Item 3.4.1.2.2-1)
21.	Implement the final version of the fuse holder interim staff guidance as provided to Duke by an NRC letter.	18.3.4	Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.	Duke letter dated 11/18/2002 (response to Item #1)

Catawba Nuclear Station
List of Committed Actions to be Implemented for License Renewal

Item	Commitment	UFSAR Section	Implementation Schedule	Source
1.	(a) Complete the Alloy 600 Aging Management review. (b) Submit the results of the review for the pressurizer surge and spray nozzle thermal sleeve attachment welds. (c) The summary aging management program descriptions contained in this UFSAR will be updated as necessary to reflect any new or revised commitments made by Duke in response to the staff generic communications that results from the Davis-Besse event in March 2002. (d) The results of this review will be incorporated into the unit specific inservice inspection (ISI) plan for the ISI intervals during the period of extended operation.	18.2.1	(a) Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. (b) Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. (c) As necessary (d) Prior to the respective ISI interval	Application B.3.1; Duke letters dated 10/28/2002 (response to New Open Item 3.1.3.2.2-2) and 11/21/2002 (Item 3)
2.	Complete the Borated Water Systems Stainless Steel Inspection.	18.2.2	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Application B.3.4

Catawba Nuclear Station
List of Committed Actions to be Implemented for License Renewal

Item	Commitment	UFSAR Section	Implementation Schedule	Source
3.	(a) Implement the Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetrations Inspection Program. (b) Update UFSAR summary description of this program to reflect any new or revised commitments made by Duke in response to the staff generic communications that result from the Davis-Besse event in March 2002.	18.2.6	(a) Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. (b) As necessary	Application B.3.9; Duke letter dated 10/28/2002 (response to New Open Item 3.1.3.2.2-2)
4.	Implement enhancements to the Fire Protection Program to provide surveillances for sprinkler branch lines, main fire pump strainer, jockey pump strainer, tank and connected piping, and turbine building manual hose stations.	18.2.8	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Application B.3.12; Duke letters dated 03/15/2002 (Commitment #9), 10/28/2002 (response to Open Items 2.3.3.19-2 & 2.3.3.19-5), and 11/18/2002 response to (Open Item 2.3.3.19-4)
5.	Complete the Galvanic Susceptibility Inspection.	18.2.11	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Application B.3.16; Duke letter dated 03/15/2002 (Commitment #10)

Catawba Nuclear Station
List of Committed Actions to be Implemented for License Renewal

Item	Commitment	UFSAR Section	Implementation Schedule	Source
6.	Implement the Inaccessible Non-EQ Medium Voltage Cables Aging Management Program.	18.2.14	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Application B.3.19; Duke letters dated 10/02/2002 (Confirmatory Item 3.6.2-1) and 11/05/2002 (Attachment 1)
7.	Implement enhancements to the Inservice Inspection Plan to provide surveillances for small bore piping.	18.2.15	During each inservice inspection interval during the period of extended operation following issuance of the renewed operating licenses for Catawba.	Application B.3.20; Duke letters dated 04/15/2002 (Commitment #1) and 11/14/2002 (response to New Open Item 3.0.3.10.2-1)
8.	Implement enhancements to the Inspection Program for Civil Engineering Structures and Components to provide surveillances for exposed external surfaces of mechanical components.	18.2.16	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Application B.3.21; Duke letter dated 10/02/2002 (response to Open Item 3.0.3.11.3-1)
9.	Complete the Liquid Waste System Inspection.	18.2.17	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Application B.3.22
10.	Complete the future modification to the Thermal Fatigue Management Program for environmentally assisted fatigue.	3.9.1	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Application 4.3; Duke letter dated 10/02/2002 (response to Open Item 4.3-4)

Catawba Nuclear Station
List of Committed Actions to be Implemented for License Renewal

Item	Commitment	UFSAR Section	Implementation Schedule	Source
11.	Implement the Non-EQ Insulated Cables and Connections Aging Management Program.	18.2.18	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Application B.3.23; Duke letter dated 10/02/2002 (response to SER Confirmatory Item 3.6.1.1)
12.	If necessary following the results of the McGuire Unit 1 examination, complete the Pressurizer Spray Head Examination.	18.2.19	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024 for Catawba Unit 1 and February 24, 2026 for Catawba Unit 2.	Duke letters dated 04/15/2002 (response to RAI 2.3.2.7-1) and 10/28/2002 (response to Open Item 3.1.2.2.2-1)
13.	Complete the Condenser Circulating Water Pump Expansion Joint Inspection.	18.2.20.2	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Duke letter dated 11/14/2002 (response to New Open Item 3.3.6.2.1-1)
14.	Implement the Reactor Vessel Internals Inspection.	18.2.22	The decision to perform inspections on Catawba Unit 1 and Catawba Unit 2 will depend on an evaluation of the internals inspections performed on McGuire Units 1 and 2.	Application B.3.27; Duke letter dated 10/28/2002 (response to New Open Items 3.1.4-1(a), (b), and (c))
15.	Complete the Selective Leaching Inspection.	18.2.23	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Application B.3.28

Catawba Nuclear Station
List of Committed Actions to be Implemented for License Renewal

Item	Commitment	UFSAR Section	Implementation Schedule	Source
16.	Complete the Sump Pump Systems Inspection.	18.2.25	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Application B.3.32
17.	Complete the Treated Water Systems Stainless Steel Inspection.	18.2.26	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Application B.3.34
18.	Complete the Ventilation Area Pressure Boundary Sealants Inspection.	18.2.28	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Duke letters dated 10/28/2002 (response to Open Item 2.3-3) and 11/14/2002 (response to Open Item 2.3-3)
19.	Complete the Waste Gas System Inspection.	18.2.29	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Application B.3.36
20.	Complete the visual inspections of the interior surfaces of Auxiliary Feedwater System and Main Feedwater System components.	18.3.3	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Duke letter dated 10/28/2002 (response to New Open Item 3.4.1.2.2-1)
21.	Implement the final version of the fuse holder interim staff guidance as provided to Duke by an NRC letter.	18.3.4	Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.	Duke letter dated 11/18/2002 (response to Item #1)

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10 SUPPLEMENTARY NOTES

11. ABSTRACT *(200 words or less)*

This safety evaluation report documents the Nuclear Regulatory Commission's (NRC's) review of Duke Energy Corporation's (Duke's) application to renew the operating licenses for McGuire Nuclear Station, Units 1 and 2 (McGuire 1 and 2), and Catawba Nuclear Station, Units 1 and 2 (Catawba 1 and 2). The NRC's Office of Nuclear Reactor Regulation has reviewed the McGuire 1 and 2 and Catawba 1 and 2 license renewal application for compliance with the requirements of Title 10 of the Code of Federal Regulations, Part 54 (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and prepared this report to document its findings.

On June 13, 2001, Duke submitted applications for renewal of McGuire 1 and 2 Operating License Nos. NPF-9 and NPF-17, which were issued pursuant to Section 103 of the Atomic Energy Act of 1954, as amended, for a period of up to 20 years beyond the current license expiration dates of June 12, 2021, and March 3, 2023, for McGuire 1 and 2, respectively. In the same submittal of June 13, 2001, Duke requested renewal of the Catawba 1 and 2 Operating License Nos. NPF-35 and NPF-52, which were issued under Section 103 of the Atomic Energy Act of 1954, as amended, for a period of up to 19 years beyond the current license expiration dates of December 6, 2024, and February 24, 2026, respectively.

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12 KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*

10 CFR Part 54, license renewal, McGuire, Catawba, scoping and screening, aging management, time-limited aging analysis, safety evaluation report

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