Duke Power
A Duke Energy Company

Ken S. Canady
Vice President
Nuclear Engineering

Duke Energy Corporation
526 South Church St.
Charlotte, NC 28202
EC08H
P.O. Box 1006
(704) 382-4712 OFFICE
(704) 382-7852 FAX

March 15, 2002

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Subject: Response to Requests for Additional Information in Support of the Staff Review of the Application to Renew the Facility Operating Licenses of McGuire Nuclear Station, Units 1 & 2 and Catawba Nuclear Station, Units 1 & 2

Docket Nos. 50-369, 50-370, 50-413 and 50-414

Dear Sir:

By letter dated June 13, 2001, Duke Energy Corporation (Duke) submitted an Application to Renew the Facility Operating Licenses of McGuire Nuclear Station and Catawba Nuclear Station (Application). The staff is reviewing the information provided in the Application and has identified areas where additional information is needed to complete its review.

In a letter dated January 23, 2002, the staff requested additional information concerning the aging management review of auxiliary systems. Attachment 1 provides the Duke response to this letter. Some of these responses contain commitments. The commitments are restated in Attachment 4 to facilitate tracking and management.

In a letter dated January 28, 2002, the staff requested additional information concerning its review of the aging management review of engineered safety features. Attachment 2 provides the Duke response to this letter. Some of these responses contain commitments. The commitments are restated in Attachment 4 to facilitate tracking and management.

In another letter dated January 28, 2002, the staff requested additional information concerning its review of the aging management programs for mechanical systems. Attachment 3 provides the Duke response to this letter. Some of these responses contain commitments. The commitments are restated in Attachment 4 to facilitate tracking and management.

A085

If there are any questions, please contact Bob Gill at (704) 382-3339.

Very truly yours,

K. S. Canady

Attachments

Affidavit

K. S. Canady, being duly sworn, states that he is a Vice President, Nuclear Generation Department, Duke Energy Corporation; that he is authorized on the part of said Corporation to sign and file with the U. S. Nuclear Regulatory Commission the attached responses to staff requests for additional information relative to its review of the Application to Renew the Facility Operating Licenses of McGuire Nuclear Station and Catawba Nuclear Station, Docket Nos. 50-369, 50-370, 50-413 and 50-414 dated June 13, 2001, and that all the statements and matters set forth herein are true and correct to the best of his knowledge and belief. To the extent that these statements are not based on his personal knowledge, they are based on information provided by Duke employees and/or consultants. Such information has been reviewed in accordance with Duke Energy Corporation practice and is believed to be reliable.

K. S. Canady

K. S. Canady, Vice President
Duke Energy Corporation

Subscribed and sworn to before me this 15TH day of March 2002.

Mary P. Nelms

Notary Public

My Commission Expires:

JAN 22, 2006

xc: (w/ Attachment)

L. A. Reyes
Regional Administrator, Region II
U. S. Nuclear Regulatory Commission
Atlanta Federal Center
61 Forsyth Street, SW, Suite 23T85
Atlanta, GA 30303

D. B. Matthews
Director, Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Senior NRC Resident Inspector
McGuire Nuclear Station

Senior NRC Resident Inspector
Catawba Nuclear Station

C. P. Patel
Senior Project Manager
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

C. I. Grimes
Program Director, License Renewal and Environmental Impacts
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

R. L. Franovich
Senior Project Manager
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

R. E. Martin
Senior Project Manager
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

xc: (w/ Attachment)

Henry J. Porter
Assistant Director, Division of Waste Management
Bureau of Land & Waste Management
S.C. Department of Health and Environmental Control
2600 Bull St.
Columbia, SC 29201

R. M. Fry
Director, Division of Radiation Protection
North Carolina Department of Environment, Health, and Natural Resources
3825 Barrett Drive
Raleigh, NC 27609

North Carolina Municipal Power Agency Number 1
1427 Meadowwood Boulevard
P.O. Box 29513
Raleigh, NC 27626

North Carolina Electric Membership Corporation
P.O. Box 27306
Raleigh, NC 27611

Piedmont Municipal Power Agency
121 Village Drive
Greer, SC 29651

Saluda River Electric Cooperative, Inc.
P. O. Box 929
Laurens, SC 29360

Attachment 1
Application to Renew the Operating Licenses of
McGuire Nuclear Station and Catawba Nuclear Station
Responses to NRC Requests for Additional Information
NRC Letter dated January 23, 2002

3.3 Auxiliary Systems (General)

RAI 3.3-1

Numerous ventilation systems included in Section 3.3 do not list elastomer components associated with the ventilation system. Normally ventilation systems contain elastomer materials in duct seals, flexible collars between ducts and fans, rubber boots, etc. For some plant designs, elastomer components are used as vibration isolators to prevent transmission of vibration and dynamic loading to the rest of the system. The aging effects of concern for those elastomer components are hardening and loss of material. Please indicate where in the LRA the aging effects of hardening and loss of material to elastomer components is addressed, or provide a justification for excluding these components from an AMR.

Response to RAI 3.3-1

The response to this RAI is in preparation and will be provided on or before April 15, 2002.

RAI 3.3-2
Clarify whether or not any of the auxiliary systems discussed in Section 3.3 of the LRA are within the category of seismic II over I systems, structures or components (SSCs) as described in position C.2 of Regulatory Guide 1.29. Also, clarify how the aging management programs provided in the AMR results tables of LRA Section 3.3 apply to those seismic II over I piping system to ensure that plausible aging effects associated with those piping systems, if any, will be appropriately managed. The applicant's discussion should include both piping segments and their associated pipe supports.

Response to RAI 3.3-2
The response to this RAI is in preparation and will be provided on or before April 15, 2002.

RAI 3.3-3

According to page 3.3-69 and 3.3-70 Table 3.3-7, certain reactor coolant (NC) pump motor upper and lower bearing cooler components have a treated water internal environment with an oil external environment. Per Tables 3.3-9 (on pages 3.3-91 to 3.3-93) and 3.3-10 (on pages 3.3-103 to 3.3-104), certain Catawba and McGuire control room area chiller components (oil cooler tubes, tube sheets and shells) are subject to an internal/external environment of treated water/oil. According to Table 3.3-16, the Catawba D/G governor lube oil coolers (tubes) are subject to an internal/external environment of treated water/oil. According to Tables 3.3-16, 3.3-20 and 3.3-21, the D/G engine lube oil coolers (tubes, tube sheets and/or shells) are listed as subject to an internal/external environment of treated water/oil. According to these referenced tables, no aging effect is identified for components exposed to the oil external environment.

Oil systems subject to water contamination are typically subject to the aging effect of loss of material. Identify where in the LRA is the AMR for the aging effect of loss of material from general, pitting, crevice, and microbiologically influenced corrosion to carbon steel or other susceptible materials exposed to oil that is potentially contaminated with leaking water, or provide a justification for excluding this aging effect from the AMR results tables.

Response to RAI 3.3-3

All of the lube oil cooler components cited in the first paragraph of RAI 3.3-3 are components of closed oil recirculation systems. Uncontaminated lube oil does not cause aging, and closed oil recirculation systems are assumed to be initially free of contaminants such as water. Further, in the Duke aging management review, component failures were not postulated as a means to establish the relevant conditions required for aging to occur. Therefore, in oil coolers, tube failures that could introduce water into a lube oil environment are not assumed.

See also the Response to RAI 3.3.36-1.

RAI 3.3-4

Per Table 3.3-8, the Catawba and McGuire carbon steel condenser circulating water system components are subject to an internal environment of raw water. Confirm that strainers do not perform a component function that may be degraded by the aging effect of fouling, neither of which is identified in Table 3.3-8 for strainers in a raw water environment. Similarly, confirm that neither orifices nor strainers, identified in Table 3.3-36, Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station), and Table 3.3-37, Aging Management Review Results - Nuclear Service Water System (Catawba Nuclear Station), perform a component function that may be degraded by the aging effect of fouling from exposure to raw water.

Response to RAI 3.3-4

The strainers in the Condenser Circulating Water System (Application Table 3.3-8 for both McGuire and Catawba) and in the Nuclear Service Water System (Table 3.3-36 for McGuire and 3.3-37 for Catawba) have a component intended function to maintain pressure boundary integrity. The component intended function of the strainer to maintain pressure boundary integrity will not be degraded by fouling. The orifices in the Nuclear Service Water System (Table 3.3-36 for McGuire and 3.3-37 for Catawba) have two component intended functions: (1) to maintain pressure boundary integrity and (2) to throttle flow. Fouling will not degrade either the pressure boundary function or the throttling function of the orifices.

RAI 3.3-5
All of the components of Table 3.3-14, "Aging Management Review for Diesel Generator Air Intake and Exhaust System," are subject to an interior environment of ventilation, which is defined as ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy. CN-1609-5.0, CN-2609-5.0, MCFD-1609-5.00 and MCFD-2609-5.00, "Flow Diagrams for Diesel Engine Air Intake and Exhaust System," do not include equipment to condition the intake air or the exhaust air for the diesels to provide a ventilation internal environment. Typically these components are subject to a sheltered internal environment.

Similarly, Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator, Exhaust Sub-System," components are subject to an internal environment of ventilation, which is defined as ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy. CN-1560-1.0, CN-1560.20, MCFD-1560-1.00, MCFD-1560.20, and MCFD-1614-4, "Flow Diagrams for Standby Shutdown Diesel System," do not include equipment to condition the intake air or the exhaust air for the diesels to provide a ventilation internal environment. Typically, these components are subject to a sheltered internal environment.

Provide justification for classifying the internal environment for these components as "ventilation."

Response to RAI 3.3-5
The Staff is correct that these components are subject to a sheltered internal environment. Duke's aging management review conservatively evaluated environments such as tanks and piping that are open to atmosphere as a ventilation environment. Although the tanks and piping are open to a sheltered environment, they would not experience significant air exchange and thus higher humidity and condensation could be present. The ventilation environment aging effect details account for the potential condensation, whereas the sheltered environment aging effect details do not. Loss of material and cracking due to alternate wetting and drying that concentrates contaminants are two aging effects considered plausible in a ventilation environment, but are not considered in a sheltered environment. Loss of material due to selective leaching is another aging effect considered plausible in a ventilation environment, but is not considered in a sheltered environment. Therefore, for conservatism, Duke chose to evaluate these component configurations using the ventilation environment aging management review details. The designation in the Application table reflects this decision.

RAI 3.3-6

Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator," identifies that the cooling water and jacket water engine radiator heat exchanger has a function of HT that is managed by the AMP, "Chemistry Control Program." Similarly, 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. Explain how the chemistry control program monitors the heat transfer function.

Response to RAI 3.3-6

For the heat exchangers in the Standby Shutdown Diesel Generator, Cooling Water and Jacket Water Heating Sub-system, Duke determined that the component intended functions that must be maintained for the period of extended operation for these heat exchangers are heat transfer and pressure boundary. For heat exchangers, fouling is the only aging effect that will result in a loss of the intended function of heat transfer. Duke determined during the aging management review that fouling would not occur for these closed loop heat exchangers because there is constant flow through the heat exchangers, and the treated water in the system is filtered to remove particles. Therefore, no aging management program is required. Loss of material is an aging effect that could result in a loss of the intended function of pressure boundary for these heat exchangers during the period of extended operation. The *Chemistry Control Program* is credited as the aging management program to manage loss of material during the period of extended operation.

For the hydrogen recombiner heat exchangers in the Waste Gas System found in Table 3.3-47 of the Application, 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.

Please see response to RAI B.3.6-1 in Attachment 3 which also deals with the *Chemistry Control Program* and fouling of heat exchangers.

3.3.2 Boron Recycle System

RAI 3.3.2-1

Table 3.3-2 has a "Note (3)," which implies that portions of the boron recycle system may be subject to alternate wetting and drying; however, this note is not used anywhere in the table. Clarify if Note (3) is applicable to Table 3.3-2. If so, explain how this environment and associated aging effects are managed in the LRA.

Response to RAI 3.3.2-1

"Note 3," which implies some portions of the Boron Recycle System are exposed to an alternate wetting and drying environment, should not have been listed at the end of Table 3.3-2 of the Application. No components in the Boron Recycle System within the scope of license renewal are exposed to an alternate wetting and drying environment which may concentrate contaminants.

RAI 3.3.2-2
Table 3.3-2 Note (1) contains a definition of a component function "HT;" however, there are no components in Table 3.3-2 listed as performing this function. Identify components in the boron recycle system that provide the function "HT," or remove the function from Note (1).

Response to RAI 3.3.2-2
The component intended functions of "HT" and "TH" should not have been listed under "Note 1" at the end of Table 3.3-2 of the Application. The only component intended function of the components listed in Table 3.3-2 is pressure boundary (PB).

3.3.9 Control Area Chilled Water System

RAI 3.3.9-1

Tables 3.3-9 and 3.3-10 indicate that the "Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program" is credited for managing the aging effects of fouling and loss of material for copper-nickel alloy materials. The Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program, as defined in Appendix B of the applicant's LRA, manages for the loss of material or fouling for admiralty brass, carbon steel, and stainless steel materials; but Appendix B's description does not include the material copper-nickel within the scope of the Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program. Explain how the Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program manages for the loss of material or fouling for copper-nickel alloy materials, or provide an AMP for managing these aging effects for this material.

Response to RAI 3.3.9-1

The *Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program* as described in Section B.3.17.4 of Appendix B is credited for managing fouling and loss of material for the copper-nickel alloy tubes. The copper-nickel alloy material was inadvertently omitted from the introductory paragraph in the program description in Appendix B of the Application. The program description does describe how fouling and loss of material of the copper-nickel alloy heat exchanger tubes are managed.

For the McGuire UFSAR Supplement Section 18.2.13.4, the last sentence in the paragraph will be revised to read as follows:

The *Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program* is credited for managing loss of material or fouling for admiralty brass, carbon steel, copper-nickel alloy, and stainless steel materials.

For the Catawba UFSAR Supplement Section 18.2.12.4, the last sentence in the paragraph will be revised to read as follows:

The *Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program* is credited for managing loss of material or fouling for admiralty brass, carbon steel, copper-nickel alloy, and stainless steel materials.

3.3.14 Diesel Generator Air Intake and Exhaust System

RAI 3.3.14-1

Table 3.3-14, "Aging Management Review for Diesel Generator Air Intake and Exhaust System," does not list an internal environment, which has the potential for exposure of components to hot diesel engine exhaust gasses containing moisture and particulates. Identify where in the LRA is the AMR for steel components exposed to a hot diesel exhaust environment that have the potential for experiencing loss of material from general, pitting and crevice corrosion, or provide a justification for excluding this environment and aging effects from Table 3.3-14 and an AMR.

Response to RAI 3.3.14-1

Table 3.3-14 of the Application presents the results of the aging management review for the Diesel Generator Intake and Exhaust System components. The diesel generators are normally in standby and are operated periodically for a short period of time for surveillance testing. During diesel operation, the exhaust portion of this system will be exposed to hot gasses containing moisture and particulates. Exposure duration of the exhaust components to the hot gasses containing moisture and particulates is insignificant when compared to the exposure time of these components to the cool, ventilation environment. As a result, the internal environment of hot gasses containing moisture and particulates was not considered in the aging management review to identify the aging effects requiring management. Therefore, Table 3.3-14 listed ventilation as the internal environment and did not include hot gases as an internal environment.

RAI 3.3.14-2
Table 3.5-2, "Aging Management Review Results for Other Structures," indicates rubber materials in a sheltered environment are subject to the aging effects of cracking and change in material properties. Please explain why the rubber and composite rubber materials of Table 3.3-14, that are also in a sheltered environment, are not subject to the aging effects of cracking and change in material properties.

Response to RAI 3.3.14-2
Elastomers could crack due to exposure to ultraviolet radiation, ozone, elevated temperature, or irradiation. Elastomers could experience a change in material properties due to exposure to elevated temperatures or irradiation. Damaging levels of radiation, temperature, and ozone are not present throughout the entire sheltered environment. As a result, elastomer location must be considered to identify the aging effects requiring management. The elastomers in Table 3.3-14 of the Application are located in the diesel room. Radiation, temperature, and ozone are below the levels to be a concern in this location. Therefore, no aging effects requiring management were identified for these elastomers.

3.3.15 Diesel Generator Cooling Water System

RAI 3.3.15-1

Table 3.3-15, "Aging Management Review Results for Diesel Generator Cooling Water System (McGuire Nuclear Station)," states that the aging effect loss of material in a raw water environment to the diesel generator cooling water heat exchangers is managed by the "Galvanic Susceptibility Inspection" aging management program (AMP). The scope of this program, as defined in Appendix B, Section B.3.16, does not include the diesel generator cooling water heat exchangers. Does the AMP, "Galvanic Susceptibility Inspection," manage the aging effects to the diesel generator cooling water heat exchangers? If not, identify an appropriate AMP.

Response to 3.3.15-1

The diesel generator cooling water heat exchangers reject heat from the Diesel Generator Cooling Water System to the Nuclear Service Water System. The channel heads and tube sheets are constructed of carbon steel that are electrolytically coupled to stainless steel and copper, respectively, in the presence of raw water supplied by the Nuclear Service Water System. The scope of the *Galvanic Susceptibility Inspection* as described in Appendix B of the Application includes the galvanic couples of the Nuclear Service Water System which would include the galvanic couples in the portion of the diesel generator cooling water heat exchangers exposed to raw water in the Nuclear Service Water System.

3.3.20 Diesel Generator Lube Oil System

RAI 3.3.20-1

Tables 3.3-20 and 3.3-21, "Aging Management Review Results for Diesel Generator Lube Oil System (McGuire Nuclear Station)," states that the aging effect of cracking and loss of material in a lube oil environment is managed by the AMP, "Chemistry Control Program." The scope of this program as defined in Appendix B, Section B.3.6, only refers to fuel oil environments and not lube oil. Does the AMP, "Chemistry Control Program," manage the aging effects in lube oil environments? If not, identify an appropriate AMP.

Response to RAI 3.3.20-1

Another review of Tables 3.3-20 and 3.3-21 of the Application shows that no aging effects were identified for system components exposed to the lube oil environment. Duke license renewal engineering documents confirm that no aging effects were identified for system components exposed to the lube oil environment. As a result, no aging management programs were identified. The *Chemistry Control Program* was identified in these tables to manage the aging effects of cracking and loss of material of diesel generator lube oil cooler components exposed to a treated water environment. The treated water environment is cooling water supplied by the Diesel Generator Cooling Water System which is within the *Chemistry Control Program* scope as shown on page B.3.6-1 of Appendix B of the Application.

3.3.22 Diesel Generator Room Sump Pump System

RAI 3.3-22-1

Table 3.3-22, "Aging Management Review Results for the Diesel Generator Room Sump Pump System," states that orifices provide the function "PB." Typically, orifices also provide the function listed in Note 1 as "TH." Explain why orifices in the diesel generator room sump pump system do not provide the function "TH," or correct the component functions for orifices listed in Table 3.3-22.

Response to RAI 3.3-22-1

The system intended function of the Diesel Generator Room Sump Pump System is to remove the contents of the Diesel Generator Room Sump to prevent room flooding that could damage equipment. The orifice included in Table 3.3-22 is located in a normally isolated recirculation line that is only used for testing the Diesel Generator Room Sump Pumps. Throttling is, therefore, not an intended function of the orifice for license renewal.

RAI 3.3-22-2

Table 3.3-22, "Aging Management Review Results for the Diesel Generator Room Sump Pump System," has a "Note (3), which implies that portions of the diesel generator room sump pump system may be subject to alternate wetting and drying; however, this note is not used in the table. Clarify if note (3) is applicable to Table 3.3-22. If so, explain how this environment and associated aging effects are managed in the LRA.

Response to RAI 3.3-22-2

"Note 3," which implies some portions of the Diesel Generator Room Sump Pump System are exposed to an alternate wetting and drying environment, is not applicable to Table 3.3-22 of the Application. No components in the Diesel Generator Room Sump Pump System within the scope of license renewal are exposed to an alternate wetting and drying environment which may concentrate contaminants.

3.3.24 Diesel Generator Starting Air System

RAI 3.3.24-1

Table 3.3-24, "Aging Management Review Results for the Diesel Generator Starting Air System - Catawba," identifies only a PB function for the D/G engine starting air aftercooler tubes. Explain why the heat transfer (HT) function, which ensures the system and/or component operating temperatures are maintained, is not considered in the AMR, or correct the component functions for D/G engine starting air aftercooler tubes listed in Table 3.3-24.

Response to RAI 3.3.24-1

The Diesel Generator Starting Air aftercooler is not required to transfer heat for the safety-related diesel to perform its function. The Diesel Generator Starting Air aftercooler and associated piping and components are nonsafety-related because they are not required to function for the diesel to start and operate. The aftercooler is within the scope of license renewal because both sides of the cooler have a pressure boundary function. The pressure boundary of the cooling water side of the aftercooler is safety-related because it forms a pressure boundary of the safety-related Nuclear Service Water System and is therefore within scope. The pressure boundary of the air side of the aftercooler is nonsafety-related but is seismically designed and designated Class F. Therefore, the pressure boundary of the air side of the aftercooler meets the criteria of §54.4(a)(2) and is within scope. The Class F design was applied to the system to minimize the effort to regain the diesel in a post seismic situation.

RAI 3.3.24-2

Table 3.3-24, "Aging Management Review Results for the Diesel Generator Starting Air System - Catawba," identifies that the D/G engine starting air aftercooler tubes are stainless steel and subject to loss of material from exposure to a raw water internal environment. Typically, the aging effect, fouling, is also associated with raw water environments. Identify where in the LRA is the AMR for the aging effects fouling to these components, or provide a justification for excluding this aging effect from Table 3.3-24 and an AMR.

Response to RAI 3.3.24-2

Fouling can cause a loss of heat transfer function but does not affect the pressure boundary function of the Diesel Generator Starting Air System aftercooler tubes. As discussed in the Response to RAI 3.3.24-1 above, heat transfer is not a component intended function of the aftercoolers. Since heat transfer is not an intended function, fouling is not an aging effect requiring management.

RAI 3.3.24-3

Table 3.3-24, “Aging Management Review Results for the Diesel Generator Starting Air System - Catawba,” identifies the Heat Exchanger Preventive Maintenance Program for Diesel Generator Starting Air as the aging management program to manage the aging effects of loss of material in a raw water environment for the D/G engine starting air aftercooler tubes and channel head, but not the tube sheet which is Monel 400 material. Section 18.2.12.5 of the UFSAR Supplement, “Diesel Generating Starting Air,” credits this program for managing aging of carbon steel, stainless steel and Monel materials. Does the AMP, “Heat Exchanger Preventive Maintenance Program for Diesel Generator Starting Air,” manage the aging effect loss of Monel 400 material to the D/G engine starting air aftercooler tube sheet exposed to a raw water environment? If not, please explain the intent of statements made in Section 18.2.12.5 of the UFSAR Supplement, “Diesel Generating Starting Air,” which indicates that this program is credited for managing aging of carbon steel, stainless steel and Monel materials.

Response to RAI 3.3.24-3

Table 3.3-24 and Appendix B (B.3.17.5) are correct. The *Heat Exchanger Preventive Maintenance Program for Diesel Generator Starting Air* is not credited with managing loss of material of the Monel 400 tubesheets of the diesel generator starting air aftercooler. The *Service Water Piping Corrosion Program* is credited with managing loss of material of the Monel 400 tubesheets of the diesel generator starting air aftercooler, as indicated in Table 3.3-24.

Section 18.2.12.5 of the Catawba UFSAR Supplement is in error and will be revised to read as follows:

18.2.12.5 DIESEL GENERATOR ENGINE STARTING AIR

The purpose of the *Heat Exchanger Preventive Maintenance Activities – Diesel Generator Engine Starting Air* is to manage loss of material for parts of the diesel generator engine starting air aftercoolers exposed to raw water. The *Heat Exchanger Preventive Maintenance Activities – Diesel Generator Engine Starting Air* is a condition monitoring program that monitors specific component parameters to detect the presence and assess the extent of material loss that can affect the pressure boundary function. The program is credited with managing loss of material for carbon steel and stainless steel.

RAI 3.3.24-4
Table 3.3-24, "Aging Management Review Results for the Diesel Generator Starting Air System - Catawba," identifies several components where carbon steel is exposed to an air (moist) environment with no aging effects or aging management program required. Loss of material from general, pitting, and crevice corrosion is an applicable aging effect for carbon steel materials in air environments containing moisture. General corrosion results from chemical or electrochemical reaction between the material and the air environment when both oxygen and moisture are present. Identify where in the LRA is the AMR for these aging effects, or provide a justification for excluding this aging effect from Table 3.3-24 and an AMR.

Response to RAI 3.3.24-4
Table 3.3-24 of the Application presents the results of the aging management review for the Diesel Generator Starting Air System. Loss of material due to crevice, general, galvanic, and pitting corrosion were evaluated for the Diesel Generator Starting Air System carbon steel components exposed to moist air. Duke determined that crevice, galvanic, and pitting corrosion were not a concern for the period of extended operation. Crevice and pitting corrosion are a concern in air environments where surfaces are alternately wetted and dried which could concentrate contaminants. Galvanic corrosion occurs in an air environment when dissimilar materials are wet. These conditions do not exist in the moist air portion of the Diesel Generator Starting Air System.

Duke considered loss of material due to general corrosion of the carbon steel components and determined that it was not an aging effect requiring management during the period of extended operation. Absent other influences such as wetting and drying, general corrosion of carbon steel occurs at a slow rate. The entire Diesel Generator Starting Air System is located in the same room with the diesel engines and is normally in standby. The system draws air from the diesel room to charge the tanks. The diesels are warmed to 125°F and that results in a room temperature of around 100°F. The air environment inside the system before the dryers can be characterized as stagnant warm air of a low humidity. This environment would not promote aggressive general corrosion such that the component intended function would be lost if left unmanaged for the period of extended operation. Therefore, loss of material due to general corrosion of the carbon steel components exposed to moist air is not an aging effect requiring management during the period of extended operation.

RAI 3.3.24-5

Table 3.3-24, "Aging Management Review Results for the Diesel Generator Starting Air System - Catawba," identifies environments air (dry) and air (moist) as potential environments for the diesel generator starting air system. Descriptions for these environments are not provided in Section 3.3.1 "Aging Management Review Results Tables," of the LRA. Identify where in the LRA these environments are defined, or provide additional information in Section 3.3.1 of the LRA.

Response to RAI 3.3.24-5

The two environments, air (moist) and air (dry), were provided in Table 3.3-24 to show that the air environment was not the same throughout the Diesel Generator Starting Air System. Both of these air environment variations are bounded by the "Air-Gas" environment definition in Section 3.3.1 of the Application. The Diesel Generator Starting Air System takes air from the diesel room. The air is filtered, compressed, dried and stored in tanks to be used to start the diesels. The air (moist) environment is the environment prior to the air dryers. The air (dry) environment is the environment after the air dryers.

3.3.26 Fire Protection System

RAI 3.3.26-1
Table 3.3-26, "Aging Management Review Results for the Fire Protection System - McGuire," indicate that sprinklers have a spray flow function. The last sprinkler component in Table 3.3-26 (page 3.3-164) is missing the SP designation. Correct the table, or justify why the spray flow function is not applicable to these sprinklers.

Response to RAI 3.3.26-1
The last sprinkler entry in Table 3.3-26 (page 3.3-164) should have contained the SP designation. The programs listed for this sprinkler will serve to manage the spray flow (SP) function consistent with other similar entries in Table 3.3-26.

RAI 3.3.26-2
The fire protection program is credited in the LRA with managing the aging effect fouling in raw water environments for carbon steel, brass and bronze valves. In Table 3.3-26, "Aging Management Review Results for the Fire Protection System - McGuire," there are carbon steel, brass and bronze valve body components identified in the exterior fire protection section that do not include fouling as an aging effect. Identify where in the LRA is the AMR for the aging effects fouling to these components, or provide a justification for excluding this aging effect from Table 3.3-26 and an AMR.

Response to RAI 3.3.26-2
Fouling is an applicable aging effect only for a specific set of components in the fire protection systems where a fouled condition could prevent the supplying of fire suppression water. As described in Section B.3.12.2 of the Application, *Mechanical Fire Protection Component Tests and Inspections*, fouling is managed for specific distribution components of the fire protection systems (sprinklers, hose station valves, and hydrant valves). Managing the impact of fouling on these components ensures that the system is capable of performing its function of supplying fire suppression water through the distribution components. In the Interior Fire Protection System at McGuire, fouling is an applicable aging effect for sprinklers and brass and bronze hose station valves exposed to raw water. In the Exterior Fire Protection System at McGuire, fouling is not an applicable aging effect for the cast iron hydrant valves exposed to raw water because no cast iron hydrant valves are relied upon for fire suppression distribution. This latter point differs from Catawba, where hydrant valves are relied upon for fire suppression distribution and for which fouling is an applicable aging effect.

Upon further review of Table 3.3-26 and consistent with this discussion, an error exists in the McGuire Exterior Fire Protection portion of the table. Fouling should not be an applicable aging effect for the cast iron valve bodies in the yard and exposed to raw water. The Table 3.3-26 entry for the cast iron valve bodies in the yard and exposed to raw water is supplemented to read as follows:

Component Type	Component Function	Material	Internal Environment / External Environment	Aging Effects	Aging Management Programs and Activities
Valve Bodies	PB	CI	Raw Water	Loss of Material	Galvanic Susceptibility Inspection Service Water Piping Corrosion Program Selective Leaching Inspection
			Yard	Loss of Material	Inspection Program for Civil Engineering Structures and Components

Again, this point contrasts with the Exterior Fire Protection portion of the Catawba table (Table 3.3-27), which lists fouling as an applicable aging effect for cast iron valve bodies in the yard and exposed to raw water.

The carbon steel, brass, and bronze valve body components of the Exterior Fire Protection System section of Table 3.3-26 which are the subject of this RAI are not distribution components; they are valves along the process flowpath. Fouling is not an applicable aging effect for these valves.

RAI 3.3-26-3
Table 3.3-27, "Aging Management Review Results for the Fire Protection System - Catawba," indicates a Note (4) is applicable in several locations in the table where components experience the aging effect fouling. There is no definition for Note (4) at the end of Table 3.3-27. Clarify if note (4) is applicable to Table 3.3-27. If so, explain how this "alters" the established definition for the aging effect fouling.

Response to RAI 3.3-26-3
Note 4 is applicable to Table 3.3-27. The note was inadvertently omitted from the table notes. Note 4 should read "Fire Hose Rack Valves Only." Upon further review of the Table 3.3-27, an additional notation error was discovered. The fouling entry on page 3.3-189 should contain a Note 5 instead of Note 4. Note 5 should read "Fire Hydrant Valves Only."

See response to RAI 3.3.26-2 for a discussion of fouling as an aging effect for fire protection components.

3.3.32 Liquid Waste System

RAI 3.3.32-1

Table 3.3-32, "Aging Management Review Results - Liquid Waste System," identifies stainless steel piping and loop seals at the McGuire plant that have the aging effects of loss of material and cracking due to exposure to wet/dry conditions. Identify where in the LRA the AMR for the wet/dry aging effect is and explain how it is managed by the chemistry control program, or provide a justification for excluding this environment/aging effect from Table 3.3-32 and an AMR.

Response to RAI 3.3.32-1

The aging management review results for the Liquid Waste System are presented in Table 3.3-32 of the Application. The components exposed to an alternate wet and dry environment are piping and valves associated with the loop seal shown on drawing MCFD-1565-03.00 at coordinates D-4 and drawing MCFD-2565-03.00 at coordinates L-3. The seal is established by the addition of demineralized water from the Demineralized Water System to the loop. Loss of material and cracking could occur as a result of the concentration of contaminants from alternate wetting and drying. Demineralized water contains minimal, if any, contaminants and is monitored and controlled by the *Chemistry Control Program*. Monitoring and controlling the quality of demineralized water used in plant systems such as the Liquid Waste System loop seal will minimize contaminant levels such that concentrations that could pose a concern can not be achieved through alternate wetting and drying. Therefore, the *Chemistry Control Program* will mitigate loss of material and cracking of the loop seal components exposed to alternate wetting and drying from demineralized water by monitoring and maintaining the water quality of the Demineralized Water System.

RAI 3.3.32-2
Table 3.3-32, "Aging Management Review Results - Liquid Waste System," identifies the aging effects of loss of material and cracking of stainless steel due to exposure to wet/dry conditions. Clarify if this aging effect is also applicable to the sump pump components identified in Table 3.3-32.

Response to RAI 3.3.32-2
Table 3.3-32 of the Application identified loss of material and cracking of stainless steel pipe and valves at McGuire due to exposure to alternate wet/dry conditions in a treated water environment. Loss of material and cracking of stainless steel due to exposure to wet/dry conditions does not apply to the sump pump components identified in Table 3.3-32. The sump pump components are exposed to a raw water environment only.

3.3.36 Nuclear Service Water System (McGuire Nuclear Station)

RAI 3.3.36-1

Per Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station)," centrifugal and reciprocating charging pumps and safety injection pump oil coolers (tubes and tube sheets) have a raw water internal/external environment with an oil internal/external environment. No aging effect is identified for these environments. Oil systems subject to water contamination are typically subject to the aging effect loss of material. Identify where in the LRA is the AMR for the aging effect of loss of material from general, pitting, crevice, and microbiologically influenced corrosion to stainless steel and copper-nickel materials for oil coolers potentially contaminated with leaking water, or provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

Response to RAI 3.3.36-1

All of the lube oil cooler components cited in RAI 3.3.36-1 are components of closed oil recirculation systems. Uncontaminated lube oil does not cause aging, and closed oil recirculation systems are assumed to be initially free of contaminants such as water. Further, in the Duke aging management review, component failures were not postulated as a means to establish the relevant conditions required for aging to occur. Therefore, in oil coolers, tube failures that could introduce water into a lube oil environment are not assumed.

See also the Response to RAI 3.3-3.

RAI 3.3.36-2

Per Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station)," the copper-nickel centrifugal and reciprocating charging pump and safety injection pump bearing oil cooler and centrifugal charging pump speed reducer oil cooler tubes are subject to an internal environment of raw water. Identify where in the LRA is the AMR for the aging effect of selective leaching for copper-nickel components in a raw water environment, or provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

Response to RAI 3.3.36-2

The relevant conditions required for loss of material due to selective leaching to occur in copper-nickel alloys are a temperature greater than 212°F, low flow, and high local heat fluxes. These conditions are not found in the Nuclear Service Water System. Therefore, loss of material due to selective leaching is not an aging effect requiring management during the period of extended operation for copper-nickel alloy components exposed to raw water.

RAI 3.3.36-3
Per Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station)," the copper-nickel reciprocating charging pump bearing oil cooler and fluid drive oil cooler tubes are subject to an internal environment of raw water. Identify where in the LRA the AMR for the aging effect of fouling for the copper-nickel tubes in a raw water environment is, or provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

Response to RAI 3.3.36-3
The reciprocating charging pumps are not relied upon for any event at McGuire Nuclear Station. The Nuclear Service Water side of the reciprocating charging pump bearing oil cooler and fluid drive oil cooler is only in scope because it is in Class F piping, and therefore meets the criteria of §54.4(a)(2). Loss of pressure boundary integrity could prevent satisfactory accomplishment of a safety function. Only the pressure boundary integrity of the reciprocating charging pump bearing oil cooler and fluid drive oil cooler is required to be maintained; heat transfer is not a function of the tubes. Fouling can cause a loss of heat transfer function, but does not affect the pressure boundary function of the reciprocating charging pump bearing oil cooler and fluid drive oil cooler tubes. Therefore, fouling is not an aging effect requiring management during the period of extended operation.

RAI 3.3.36-4

Per Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station)," the cast iron reciprocating charging pump fluid drive oil cooler channel covers are subject to an internal environment of raw water. Identify where in the LRA the AMR for the aging effect of selective leaching for cast iron components in a raw water environment is, or provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

Response to RAI 3.3.36-4

Loss of material due to selective leaching is an aging effect applicable only to "gray" cast iron. The reciprocating charging pump fluid drive oil cooler channel covers are constructed of "long black iron." Long black iron is carbon steel. Therefore, loss of material due to selective leaching is not an aging effect requiring management during the period of extended operation for the channel covers in Table 3.3-36 of the Application.

The Table 3.3-36 entry for the "Reciprocating Charging Pump Fluid Drive Oil Coolers (channel covers)" is in error. The Table 3.3-36 entry for the "Reciprocating Charging Pump Fluid Drive Oil Coolers (channel covers)" is replaced with the following entry:

Component Type	Component Function	Material	Internal Environment External Environment	Aging Effects	Aging Management Programs and Activities
Reciprocating Charging Pump Fluid Drive Oil Coolers (channel covers)	PB	CS	Raw Water	Loss of Material	Galvanic Susceptibility Inspection Service Water Piping Corrosion Program
			Sheltered	Loss of Material	Fluid Leak Management Program Inspection Program for Civil Engineering Structures and Components

3.3.37 Nuclear Service Water System (Catawba Nuclear Station)

RAI 3.3.37-1

Loss of material from pitting corrosion is an applicable aging effect for admiralty brass, brass, bronze, carbon steel, cast iron, copper, 90-10 copper-nickel, ductile cast iron, and stainless steel materials in a raw water environment. Pitting corrosion can be inhibited by maintaining an adequate flow rate, which prevents impurities from adhering to the material surface. The more susceptible locations for pitting corrosion to occur in materials in a raw water environment are locations of low or stagnant flow. Identify where in the LRA the AMR for the aging effect of pitting corrosion is in low flow or stagnant conditions, or provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

Response to RAI 3.3.37-1

In the Duke aging management review, pitting corrosion is considered an aging mechanism that manifests itself as loss of material. Loss of material is the aging effect requiring management for license renewal. Loss of material is identified in Table 3.3-36 for all applicable materials exposed to raw water and is managed by the *Service Water Piping Corrosion Program.*

3.3.40 Reactor Coolant Pump Motor Oil Collection Subsystem

RAI 3.3.40-1

Per Table 3.3-40, "Aging Management Review Results - Reactor Coolant Pump Motor Oil Collection Sub-System," flexible hoses are of the material type of stainless steel. Per CN-1553-1.3 and CN2553.1-3, "Flow Diagram of Reactor Coolant System (NC)," line listings for the flexible hoses between the upper bearing oil enclosures and the reactor coolant pump motor drain tank are carbon steel. Identify where in the LRA is the AMR for the reactor coolant pump motor oil collection sub-system carbon steel flexible hoses, or provide a justification for excluding these components from Table 3.3-40 and an AMR.

Response to RAI 3.3.40-1

In general, the materials identified in the line listings on Duke flow diagrams refer to pipe and pipe components and would be generally used for other system components. Materials for some engineered components may be different than the general system material, as is the case here. All of the flexible hoses shown on flow diagrams CN-1553-1.3 and CN-2553-1.3 are stainless steel. No carbon steel flexible hoses are installed within the license renewal evaluation boundaries of the Reactor Coolant Pump Motor Oil Collection Sub-System.

RAI 3.3.40-2
Per Table 3.3-40, "Aging Management Review Results - Reactor Coolant Pump Motor Oil Collection Sub-System," all components are subject to an internal environment of ventilation and an external environment of reactor building or ventilation. Explain why these components of the reactor coolant pump motor oil collection sub-system are not subject to an internal and/or external environment of oil.

Response to RAI 3.3.40-2
In accordance with plant directives and procedures, the Reactor Coolant Pump Motor Oil Collection Sub-System is not allowed to be used as an oil storage system. Any used oil that has collected in the drain tank during operation is drained from the system during each refueling outage, and the system is flushed before returning to service following the outage. Therefore, the internal environment of the system at the beginning of each operating cycle is air that enters the system from the Reactor Building environment during the fill, drain and flush operations, and oil leakage is not expected as a normal operating condition.

3.3.41 Reactor Coolant System (Non-Class1 Components)

RAI 3.3.41-1

Per Table 3.3-41, "Aging Management Review Results - Reactor Coolant System (Non-Class1 Components)," Note 3, orifices may be subjected to a borated water or steam environment. Identify where in the LRA is the AMR for the reactor coolant system orifices in a borated water or steam environment, or provide a justification for excluding these environments from Table 3.3-41 and an AMR.

Response to RAI 3.3.41-1

The orifice listed in Table 3.3-41 of the Application is located in the common reactor vessel high-point vent line, downstream from the parallel, redundant vent line isolation valve sets, which are isolated during normal plant operation. These orifices are on drawings MCFD 1553-2.01 (K-6), MCFD-2553-2.01 (K-6), CN-1553-1.1 (K-7), and CN-2553-1.1 (K-7). The vent line is normally used only during system fill operations to vent gases from the Reactor Coolant System to the pressurizer relief tank or during an accident to assure voiding does not occur in the reactor vessel head. The orifice and downstream piping between the orifice and the pressurizer relief tank are open to the pressurizer relief tank environment. As a result, the orifice is exposed to the gas environment normal to the pressurizer relief tank. Therefore, the aging management review was performed for a "gas" environment. Note 3 should not have been included at the end of Table 3.3-41.

3.3.44 Standby Shutdown Diesel System

RAI 3.3.44-1

Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator, Exhaust Sub-System," does not list an internal environment, which has the potential for exposure of components to hot diesel engine exhaust gasses containing moisture and particulates. Identify where in the LRA is the AMR for steel components exposed to a hot diesel exhaust environment that have the potential for experiencing loss of material from general, pitting, and crevice corrosion, or provide a justification for excluding this environment and aging effects from Table 3.3-44 and an AMR.

Response to RAI 3.3.44-1

The results of the aging management review for the internal surfaces of the Standby Shutdown Diesel Generator, Exhaust Sub-system are presented in Table 3.3-44 of the Application. The diesel generators are normally in standby and are operated periodically for a short period of time for surveillance testing. During diesel operation, the exhaust portion of this system will be exposed to hot gasses containing moisture and particulates. Exposure duration of the exhaust components to the hot gasses containing moisture and particulates is insignificant when compared to the exposure time of these components to the cool, ventilation environment. As a result, the internal environment of hot gasses containing moisture and particulates was not considered in the aging management review to identify the aging effects requiring management. Therefore, Table 3.3-44 listed ventilation as the internal environment.

RAI 3.3.44-2
Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator, Fuel Oil Sub-System," identifies that the shutdown diesel generator fuel oil valve bodies, fuel oil (duplex filters) (CNS only) (p 3.3-254) has a "PB" component function. This component also provides filtration of process fluids so that downstream equipment and/or environments are protected. Explain why this component does not have a "FI" component function as defined in the notes section for other AMR tables, or correct the component functions for filters listed in Table 3.3-44.

Response to RAI 3.3.44-2
The Table 3.3-44 entry "Valve Bodies, Fuel Oil (duplex filters) (CNS only)" pertains to the valves associated with the duplex filter assembly, not the filter itself. Although not necessary, the valves were differentiated because they were the only valves in the system with the given material/environment combination.

The duplex filter is addressed in the entry on Application page 3.3-249, "Filter, Duplex (mounting head)." The mounting head is the only passive, long-lived portion of the duplex filter. The filter itself is replaced during periodic diesel engine maintenance. The filter is, therefore, not considered a long-lived component, is not subject to aging management review in accordance with §54.21(a)(1)(ii) of the Rule, and is not included in Table 3.3-44.

3.3.47 Waste Gas System

RAI 3.3.47-1

Table 3.3-47, "Aging Management Review Results - Waste Gas System," identifies an internal environment described as gas. The definition for air-gas environments identified at the beginning of the tables does not adequately describe the gas environment found in the waste gas system. The waste gas system contains mixed radioactive fission gases (e.g., Kr, Xe, I, Cs) in addition to those listed in the air-gas definition. Clarify if the air-gas environment described at the beginning of the tables includes fission gases or add a new definition for the gas environment found in the waste gas system.

Response to RAI 3.3.47-1

The Waste Gas System continuously circulates nitrogen around the system loop. Hydrogen containing oxygen and fission product gasses is vented into the Waste Gas System from the volume control tanks of the Chemical and Volume Control System. Additional oxygen is added immediately upstream of the recombiners to reduce the hydrogen concentrations in the waste gas stream to residual levels. As a result, the environment is compressed nitrogen gas containing fission product gasses and is consistent with the definition of a gas environment on page 3.3-3 of the Application.

RAI 3.3.47-2

Table 3.3-47, "Aging Management Review Results - Waste Gas System," identifies that for the Catawba plant, the orifices for waste gas compressor seal and make-up have a pressure boundary "PB" component function. Typically, orifices also provide the function listed as "TH" (provide throttling so that sufficient flow and/or sufficient pressure is delivered, provide backpressure, provide pressure reduction, or provide differential pressure). Explain why orifices in the Catawba waste gas system do not provide the function "TH," or correct the component functions for orifices listed in Table 3.3-47.

Response to RAI 3.3.47-2

The waste gas compressor is a nonsafety-related component that is not required to operate in support of any function related to §54.4(a)(1) of the Rule. The components associated with the compressor are only required to maintain pressure boundary integrity in support of §54.4(a)(1)(iii). Therefore, throttling is not a license renewal intended function of the seal and make-up orifices.

Attachment 2
Application to Renew the Operating Licenses of
McGuire Nuclear Station and Catawba Nuclear Station
Responses to NRC Requests for Additional Information
NRC Letter dated January 28, 2002

3.2 Aging Management of Engineered Safety Features

RAI 3.2-1

Since closure bolting is exposed to air, moisture, and leaking fluid (boric acid) environments, it is subject to the aging effects 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. Please indicate where in the LRA the AMR results for closure bolting are documented, or provide a justification for excluding closure bolting from an AMR, the results of which are documented in the referenced tables of the LRA.

Similarly, Table 3.5-3 provides no information to address the cracking initiation and growth from SCC for high strength low-alloy bolts. 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. State whether there is such a program and provide the reference.

Response to RAI 3.2-1

The response to RAI 3.2-1 is in preparation and will be provided on or before April 15, 2002.

RAI 3.2-2

The application does not define any of the aging effect listed in Tables 3.2-1 through 3.2-8. Paragraph 3.2.1, Aging Management Review Results Tables, Column 5 states that aging effects identification process is consistent with the process used in Oconee Nuclear Station. The Oconee application defined each aging effect in its Appendix C. The staff requests that the applicant indicate if the aging effects identification process is identical to the one described in the Oconee LRA and confirm that the definitions provided in Appendix C of the Oconee LRA apply to the Catawba/McGuire LRA as well. If there are any differences between the Oconee and Catawba/McGuire LRAs, please identify them.

Response to RAI 3.2-2

As stated in Sections 3.1, 3.2, 3.3 and 3.4 of the Application, the aging effects identification process is consistent with the process previously described in the Oconee Application, Sections 3.5.1 and 3.5.2 and as evaluated by the staff in NUREG-1723.

The aging effects identification process used for McGuire and Catawba used not only the process that had been used during the Oconee aging effects identification reviews, but also industry experience and lessons learned since the Oconee review had been performed. In addition, the McGuire and Catawba review included material/environment combinations (e.g., titanium/borated water) that were not reviewed at Oconee, thus requiring new aging effects reviews to be performed. For these reasons, Duke concluded that the process used for the McGuire and Catawba aging effects review was consistent with that used at Oconee, but not identical.

The Oconee Application defined each aging effect for mechanical components in Section 3.5.2, not in Appendix C as the RAI states. Duke confirms that the definitions previously provided in the Oconee Application apply to the McGuire - Catawba Application as well.

RAI 3.2-3
In Table 3.2-2, on page 3.2-22, the applicant specifies the Fluid Leak Management Program and the Inspection Program for Civil Engineering Structures and Components as the aging management programs (AMPs) for carbon steel valve bodies. However, on page 3.2-23, the applicant specifies only the Inspection Program for Civil Engineering Structures and Components as the AMP for carbon steel valve bodies. (1)Does the Fluid Leak Management Program Scope include mechanical systems and components outside the reactor building? (2)Does the LRA reflect an assumption that boric acid corrosion can occur only in a reactor building environment and not in a sheltered environment? (3)Or are the steam generator wet lay-up system carbon steel valve bodies in a sheltered environment that houses no potential sources of leaking borated water?

Response to RAI 3.2-3
In response to item (1), the *Fluid Leak Management Program* scope does include mechanical systems and components outside the Reactor Building. As stated in Appendix B.3.15, the *Fluid Leak Management Program* manages loss of material due to boric acid wastage for susceptible materials located in the Auxiliary and Reactor Buildings.

In response to item (2), the Application does not reflect an assumption that boric acid corrosion can occur only in a Reactor Building environment and not in a sheltered environment. Loss of material due to boric acid wastage of various susceptible materials could occur in the Auxiliary Building as well as the Reactor Building.

In response to item (3), the Steam Generator Wet Lay-Up System carbon steel valve bodies are located in the Main Steam Doghouse, a sheltered environment that houses no potential sources of leaking borated water.

RAI 3.2-4
In Table 3.2-7, the applicant identifies that the internal surfaces of the carbon steel residual heat removal (ND) heat exchanger (HX) shells and ND pump seal water HX shells are both exposed to treated water environments. Clarify either by reference to appropriate information in the application or by discussion why cracking is identified as an applicable aging effect for the ND HX shells but not for the ND pump seal water HX shells.

Response to RAI 3.2-4
Cracking should have also been identified for the ND pump seal water HX shells. An error occurred in translating the information from the technical document to the Application. The technical document indicates cracking as an aging effect requiring management for the ND pump seal water HX shells and the *Chemistry Control Program* as the aging management program to manage the cracking.

The Table 3.2-7 entry for "RHR Pump Seal Water (shell)" in the Application is replaced with the following entry:

Component Type	Component Function	Material	Internal Environment / External Environment	Aging Effects	Aging Management Programs and Activities
RHR Pump Seal Water (shell)	PB	CS	Treated water	Loss of Material	Chemistry Control Program
				Cracking	Chemistry Control Program
			Sheltered	Loss of Material	Fluid Leak Management Program Inspection Program for Civil Engineering Structures and Components

The *Chemistry Control Program* is described in Section B.3.6 of the Application.

RAI 3.2-5
In Table 3.2-8, you identify that the external surfaces of some of the carbon steel piping and valve bodies in the safety injection (NI) systems are exposed to sheltered air environments. Clarify either by reference to appropriate information in the application or by discussion why loss of material is identified as an applicable aging effect for the carbon steel NI piping that is exposed sheltered air but not for the carbon steel NI valve bodies that are exposed to the same environment.

Response to RAI 3.2-5
The Staff is correct. The entry in Table 3.2-8 of the Application for carbon steel valves bodies in a sheltered environment should have the same aging effects and aging management programs as the table entry for carbon steel pipe in a sheltered environment.

The Table 3.2-8 entry for the carbon steel valve bodies in a sheltered environment is replaced with the following entry:

Component Type	Component Function	Material	Internal Environment / External Environment	Aging Effects	Aging Management Programs and Activities
Valve Bodies	PB	CS	Air-Gas	None Identified	None Required
			Sheltered	Loss of Material	Fluid Leak Management Program Inspection Program for Civil Engineering Structures and Components

RAI 3.2-6

Table 3.2-2, Aging Management Review Results - Containment Isolation System, on page 3.2-16 of the LRA indicates that Ice Condenser Refrigeration System carbon steel piping exposed to the reactor building external environment (the third "Pipe" entry from the top of the page) has no identified aging effects. The staff questions why this piping was not identified as susceptible to loss of material and subject to the Fluid Leak Management Program and the Inspection Program for Civil Engineering Structures and Components. This finding appears to be inconsistent with the LRA's treatment of similar or identical materials and components in the same environment.

Response to RAI 3.2-6

The Staff is correct. The entry in Table 3.2-2 of the Application for carbon steel pipe in the Ice Condenser Refrigeration System exposed to the Reactor Building environment should have the same aging effects and aging management programs as the other carbon steel components exposed to the Reactor Building environment.

The Table 3.2-2 entry for the carbon steel pipe in the Reactor Building environment is replaced with the following entry:

Component Type	Component Function	Material	Internal Environment External Environment	Aging Effects	Aging Management Programs and Activities
Pipe	PB	CS	Ventilation (Note 5)	None Identified	None Required
			Reactor Building	Loss of Material	Fluid Leak Management Program Inspection Program for Civil Engineering Structures and Components

Attachment 3
Application to Renew the Operating Licenses of
McGuire Nuclear Station and Catawba Nuclear Station
Responses to NRC Requests for Additional Information
NRC Letter dated January 28, 2002

B.3.4 Borated Water Systems Stainless Steel Inspection

RAI B.3.4-1

The LRA proposes that one of twelve possible inspection locations at each plant will be inspected volumetrically as part of the Borated Water Systems Stainless Steel Inspection program (monitoring & trending). Stainless steel (SS) has demonstrated susceptibility to intergranular stress corrosion cracking (IGSCC) in low-temperature borated water systems in pressurized water reactors, particularly in stagnant lines, at weld heat-affected zones (HAZs), involving weld procedures that resulted in sensitization of the stainless steel in the HAZs. Since IGSCC has a wide range of induction and propagation rates, depending on degree of sensitization, local stresses, and specific impurities at a given location, justify why only a one-time inspection is sufficient. Also, since not all welds, stress patterns, and impurity levels and species are necessarily similar, justify why inspection of only one of twelve locations adequately represents the durability of material at the other eleven locations and explain the process for inspection population expansion should aging effects be identified.

Response to RAI B.3.4-1

The one-time *Borated Water Systems Stainless Steel Inspection* is proposed to characterize any loss of material or cracking of stainless steel components exposed to alternate wetting and drying borated water environments. Uncertainty exists as to whether alternate wetting and drying of the borated water could cause aging in stainless steel components such that they may lose their pressure boundary function in the period of extended operation. A search of site operating experience did not reveal any instances of failure of stainless steel components exposed to this type of environment. Although there was no site operating experience to suggest a concern, technical literature suggests the possibility of occurrence. Since the aging effects could not be absolutely ruled out, Duke decided that an inspection was warranted. Duke does not believe loss of material and cracking of stainless steel components exposed alternate wetting and drying is occurring. The proposed one-time inspection is to confirm our position.

The *Borated Water Systems Stainless Steel Inspection* proposes that one of twelve possible locations at each station be inspected. Duke intends to evaluate all the possible locations and select the one that would most likely result in the identification of loss of material or cracking if they are occurring. The twelve locations for inspection are exposed to the ambient conditions of the upper containment of the Reactor Building (less than 100°F and at atmospheric pressure). Criteria such as geometry, proximity to hot equipment, and operating experience will be used to select the locations for inspection. As noted in Section B.3.4 of Appendix B of the Application, if no parameters are known that would distinguish one location over the others, one location will be examined based on accessibility and radiological considerations. Because there is no

operating experience to suggest an aging effect concern and the environment at the inspection locations is not particularly aggressive, Duke believes inspection of one of the twelve possible locations at each site is sufficient.

As for inspection population expansion, if either loss of material or cracking is found during the initial inspection, the plant Problem Investigation Process will be implemented to perform an engineering evaluation of operability, inspection of similar locations, and the development of corrective actions that may provide programmatic oversight that may include future inspections.

RAI B.3.4-2
The LRA proposes that a one-time inspection be performed and that no actions are to be taken to trend inspection results (monitoring & trending). The LRA also states that if an engineering evaluation determines that the aging effects, identified during the one-time inspection, will not result in a loss of the component's intended function(s) during the period of extended operation, then no further action will be required. Industry experience has shown that, under this environment, SCC damage tends to result in leaks that are somewhat localized. In this light, explain the basis for not performing future inspections at those locations in which aging effects have been identified in order to ensure that degradation predictions made in the engineering evaluations remain valid (detection of aging effects and monitoring & trending).

The staff and applicant participated in a conference call on October 25, 2001. A summary of this conference call was issued December 12, 2001. During this conference call, the applicant indicated that engineering judgment would be applied to determine if corrective actions are warranted based upon the results of the one-time inspection. Provisions for programmatic oversight would be established at the time the results of the inspection are obtained, and the inspection results, as well as corrective actions taken by the applicant (licensee), would be subject to NRC inspection at the appropriate time in the future. The staff requests information necessary to determine the appropriateness of not performing future inspections at those locations in which aging effects have been identified in order to ensure that degradation predictions made in the engineering evaluations remain valid (detection of aging effects and monitoring & trending). In particular, the staff requests that the applicant describe the criteria for (1) assessing the severity of the observed degradation, and (2) determining whether or not corrective action is necessary.

Response to RAI B.3.4-2
The acceptance criteria for the *Borated Water Systems Stainless Steel Inspection* is no unacceptable loss of material or cracking that could result in a loss of the component intended function(s). If evidence of loss of material or cracking is observed during the initial inspection, a problem report will be developed in accordance with Problem Investigation Process of Nuclear System Directive 208. The Problem Investigation Process is a formalized process for documenting engineering evaluations of plant problems that would include the assessment of the severity of the observed degradation, the need for corrective actions, the need for further inspections of other locations, and the need for future inspections or programmatic oversight. Criteria such as ASME Code requirements, additional inspection results, and operating experience may be used to assess the severity of the degradation and the need for corrective actions. Any criteria involved in determining the severity of the degradation and the need for corrective action will be developed at the time of the evaluation and will be a part of the problem

report. Duke believes it is premature to specify the actual criteria for determining severity and the need for corrective actions for an inspection that will occur 15 to 20 years from now.

RAI B.3.4-3

The LRA states that the parameters inspected by the borated water systems stainless steel inspection program are pipe wall thickness, as a measure of loss of material, and evidence of cracking (parameters monitored or inspected). Will the inspections be also looking for evidence of pitting? If so, discuss the inspection technique(s) that will be used to reliably identify the presence of pits (monitoring & trending).

Response to RAI B.3.4-3

The *Borated Water Systems Stainless Steel Inspection* requires that volumetric examination techniques be used to detect loss of material, which includes evidence of pitting, of the stainless steel components exposed to alternate wetting and drying borated water environments. The presence of a few pits would not be a structural concern that could lead to loss of component intended function. Heavy pitting would be revealed as general wall loss by volumetric examination techniques. Duke believes that, after what will then be almost forty years of service, if pitting were occurring to the extent to be a concern, then the pits would be numerous enough to be detectable by volumetric examination techniques in this one-time inspection.

B.3.6 Chemistry Control Program

RAI B.3.6-1

In the LRA's description of the Chemistry Control Program, two aging effects were specified: loss of material and cracking. However, in addition to these two effects, the water chemistry environment could cause fouling of the heat transfer surfaces in heat exchangers. Tables 3.1-1 through 3.4-1 of the LRA show that this could occur in the following heat exchangers:

Auxiliary Building Ventilation System
- shutdown panel area air conditioning unit condenser tubes

Component Cooling (KC) System
- heat exchanger KC
- heat exchanger containment spray (NS) pump motor cooler
- heat exchanger chemistry and volume control system (NV) centrifugal charging pump bearing oil cooler
- heat exchanger safety injection (NI) pump bearing oil cooler.

Control Area Chilled Water System
- control room area chiller (evaporator tubes)

Control Area Ventilation System
- air handling units heat exchangers

Diesel Generator (D/G) Cooling Water
- D/G engine cooling water heat exchanger
- D/G engine cooling water turbocharger intercoolers
- D/G engine jacket water coolers

Spent Fuel Cooling System
- heat exchangers

Waste Gas System
- hydrogen recombiner heat exchangers

Explain why fouling of the heat transfer surfaces in the above listed heat exchangers are not classified as an aging effect managed by the chemistry control program.

Response to RAI B.3.6-1

Fouling of the heat exchangers listed in the RAI is managed by the *Chemistry Control Program.* The *Chemistry Control Program* as described in Appendix B of the Application did not include fouling of heat exchangers exposed to treated water as one the aging effects managed by the program. Fouling should have been included as one of the aging effects managed by the *Chemistry Control Program.* The heat exchangers listed could experience fouling due to silting during the period of extended operation. Fouling due to silting is the result of corrosion product

buildup in the heat exchangers. Each of the heat exchangers listed is cooled by a closed cooling water system. The *Chemistry Control Program* maintains the environment in the closed cooling water systems through the use of corrosion inhibitors. Mitigation of corrosion by the use of corrosion inhibitors mitigates the production of corrosion products that could be transported to the heat exchangers. By mitigating the production of corrosion products, fouling is prevented.

The summary description of the *Chemistry Control Program* is contained in McGuire UFSAR Supplement Section 18.2.4 and Catawba UFSAR Supplement Section 18.2.4. The second sentence of each summary will be revised to read as follows:

This program manages the relevant conditions that lead to the onset and propagation of loss of material, cracking, and fouling which could lead to a loss of structure or component intended functions.

RAI B.3.6-2
In the LRA, the applicant stated that the chemistry control program is controlled by the site program manuals, which are based on the guidance contained in several sources including the Electrical Power Research Institute (EPRI) chemistry guidelines. Specify to what extent the procedures in the site program manuals deviate from the EPRI guidelines for secondary water chemistry.

Response to RAI B.3.6-2
The site chemistry manuals concerning secondary chemistry are based on the EPRI guidelines for secondary water chemistry. EPRI chemistry guidelines allow for plant-specific deviations with proper technical documentation to justify the deviation. Duke has a few deviations for secondary water chemistry. The technical documentation justifying the deviations are on site and available for staff review during the site inspections.

RAI B.3.6-3
Specify the acceptance criteria for fuel oil and specify the standards used in developing these acceptance criteria.

Response to RAI B.3.6-3
For McGuire, the acceptance criteria and standards for fuel oil are specified on page B.3.8.3-4 of McGuire Nuclear Station, *Technical Specification Bases*, Volume 2, for surveillance requirement 3.8.3.2. For Catawba, the acceptance criteria and standards for fuel oil are specified on page B.3.8.3-5 of Catawba Nuclear Station, *Technical Specifications*, for surveillance requirement 3.8.3.3.

RAI B.3.6-4
Specify any deviations in the parameters monitored for each of the four chemistries specified in the LRA from the parameters specified in the corresponding standards of EPRI chemistry guidelines.

Response to RAI B.3.6-4
The parameters monitored at Catawba and McGuire are based on the EPRI chemistry guidelines for primary water, secondary water, and closed cooling water systems. The EPRI chemistry guidelines allow plant specific deviations with proper technical documentation to justify the deviation. Duke has a few deviations with the technical documentation justifying the deviations on site and available for staff review during the site inspections. The fuel oil systems do not have an EPRI guideline for monitoring. Please see response to RAI B.3.6-3 for information concerning fuel oil monitoring acceptance criteria and standards.

B.3.12.2 Mechanical Fire Protection Component Tests and Inspections

RAI B.3.12.2-1

The application states in Section B.3.12.2, "Mechanical Fire Protection Component Tests and Inspections-Monitoring and Trending", of the LRA that a sample of sprinklers are either inspected or replaced after 50 years of operation. Describe the basis for the sampling process. Also, provide the rationale for either inspection or replacement of only some of the sprinklers after 50 years of operation.

Response to RAI B.3.12.2-1

The rationale for replacement or testing comes from NFPA 25 – 1998, Section 2-3.1.1 which states:

> Where sprinklers have been in service for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory acceptable to the authority having jurisdiction for field service testing.

Samples will be selected based on the different environments (temperature, humidity, etc.) that the sprinklers were exposed to during their 50 year service life.

RAI B.3.12.2-2
With regard to the monitoring and trending activities, fouling of hose station valves and sprinklers are managed by flow tests and flushes which are governed by Selected Licensee Commitment (SLC) 16.9.1(a)(iii) at Catawba and Testing Requirement (TR) 16.9.1.3 at McGuire. What are the differences between these two requirements?

Response to RAI B.3.12.2-2
The content of the two requirements is the same. They simply have different numbers. McGuire recently converted their Selected Licensee Commitments (SLC) to a standardized Technical Specification format. Catawba has not yet completed their conversion. Therefore, the surveillance numbering scheme is different between the plants' SLCs.

RAI B.3.12.2-3
With regard to the monitoring and trending activities, the integrity of the sprinkler branch lines is assured by sprinkler system flow tests which are governed by Selected Licensee Commitment TR 16.9-2(a)(iv)(1) at Catawba. This test is not governed by Selected Licensee Commitment at McGuire, but is performed to satisfy a specific plant procedure. Specify the governing requirements for this test at McGuire and how these requirements differ from those at Catawba, and why.

Response to RAI B.3.12.2-3
During original licensing of McGuire, the sprinkler system flow test was not a required Technical Specification surveillance. During subsequent Catawba licensing, the surveillance was required to be placed in Technical Specifications. Since it was never in the original McGuire Technical Specifications, it was not placed into the Selected Licensee Commitments (SLC) during the allowed conversion. Since the test is committed as part of an aging management program for license renewal, the sprinkler system flow test will be added to the McGuire UFSAR Supplement. The revision to the McGuire UFSAR Supplement is captured in the response to RAI B.3.12.2-4 in conjunction with UFSAR Supplement changes for that RAI.

RAI B.3.12.2-4
With regard to the monitoring and trending activities, explain the basis for the sample disassembly inspection program for managing the fouling of sprinkler branch lines. Specifically, explain how the sample of branch lines is selected (basis for selection) and how the number of branch lines to be sampled is determined (basis for sample size).

Response to RAI B.3.12.2-4
In light of the view that the potential for general corrosion is accelerated by introducing new oxygen to the system when the system is opened (see RAI B.3.12.2-5), Duke would like to revise this aspect of the *Mechanical Fire Protection Component Tests and Inspections* as described in Section B.3.12.2 of the Application. Fouling of sprinkler branch lines that do not receive flow during flow tests was to be managed by disassembling the piping and visually inspecting the interior surfaces. Duke proposes a combination of volumetric examination, such as radiography, and possibly sample disassembly to manage fouling of these branch lines. Some radiography of the Fire Protection piping has already been performed and provides excellent indication of corrosion product build-up in the lines. Duke proposes using volumetric examination as a screening tool to determine if it is necessary to perform further intrusive inspections.

The branch line samples to be inspected by volumetric examination will be selected based on several factors. Samples will be chosen to try to obtain a representative sampling of the various environments (temperatures, flow conditions, etc.) the sprinkler systems have been exposed to. Also, samples will be chosen based on pipe configurations that would lend themselves to worst case fouling (e.g., low points, multiple bends, etc.). The sample size will be determined based on obtaining a representative sample that would bound all of the selection parameters mentioned above. If the volumetric examination results indicate the need to perform further intrusive inspections on a particular branch line, then that branch line will be inspected as described in the Section B.3.12.2 of the Application.

The McGuire UFSAR Supplement Section 18.2.8 will be revised to read as follows:

> Elements of the *Fire Protection Program* that serve to manage aging are implemented in accordance with Selected Licensee Commitments (See Table 18-1). The integrity of the sprinkler branch lines is assured by sprinkler flow tests performed by procedure every 18 months.
>
> Additionally, fouling of sprinkler branch lines that do not receive flow during periodic testing will be managed. Since these lines do not receive flow, it is believed that they are less susceptible to fouling than the lines that receive flow during testing. To validate this belief, branch lines of a few representative sprinkler systems will be volumetrically examined. Subsequent examinations for the period of extended operation will be determined based on the initial examination results.
>
> For McGuire, this volumetric examination 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 Unit 1).

The Catawba UFSAR Supplement Section 18.2.8 will be revised to read as follows:

> Elements of the *Fire Protection Program* that serve to manage aging are implemented in accordance with Selected Licensee Commitments (See Table 18-1).
>
> Additionally, fouling of sprinkler branch lines that do not receive flow during periodic testing will be managed. Since these lines do not receive flow, it is believed that they are less susceptible to fouling than the lines that receive flow during testing. To validate this belief, branch lines of a few representative sprinkler systems will be volumetrically examined. Subsequent examinations for the period of extended operation will be determined based on the initial examination results.
>
> For Catawba, this volumetric examination will be completed following issuance of renewed operating licenses for Catawba Nuclear Station and by December 26, 2024 (the end of the initial license of Catawba Unit 1).

RAI B.3.12.2-5
The staff proposes to revise the Fire Protection system aging management program inspection criteria in NUREG-1801 for wall thinning of piping due to corrosion. Each time the system is opened, oxygen is introduced into the system, and this accelerates the potential for general corrosion. Therefore, the staff recommends that a non-intrusive means of measuring wall thickness, such as ultrasonic inspection, be used to detect this aging effect. The staff recommended action in this regard is that, in addition to an ultrasonic inspection of the fire protection piping before exceeding the current licensing term, the applicant perform ultrasonic inspections immediately after the 50-year service life sprinkler head testing, in accordance with NFPA 25, Section 2.3.3.1, and at 10-year intervals thereafter.

Verify whether or not the aging management program inspection criteria for Fire Protection system piping at Catawba/McGuire conforms with the staff position, as outlined above.

Response to RAI B.3.12.2-5
The NFPA 25 section referred to in the RAI related to 50-year service life sprinkler head testing is NFPA 25, Section 2-3.1.1.

The *Service Water Piping Corrosion Program*, discussed in Section B.3.29 of the Application, manages wall thinning of piping due to corrosion of Fire Protection systems. The program uses ultrasonic inspection, a non-intrusive method, to manage this aging effect. The nature of the program does not prescribe inspections at the specified times outlined by the staff position, but does ensure reinspection at an appropriate frequency based on the calculated corrosion rate. (See response to RAI B.3.29-2.) The program will likely impose inspections more frequently than that outlined in the staff's position. The program is an existing program with adequate operating experience to provide reasonable assurance that it will manage the aging of fire protection systems as successfully as it has managed other raw water systems in the plant.

RAI B.3.12.2-6
Describe the environmental and material conditions that exist on the interior surface of below-grade FP piping. If these conditions can be demonstrated to be similar to the conditions existing in the above-grade FP piping, then the inspections in the above-grade piping may be extrapolated to evaluate the interior conditions of the below-grade piping. If not, additional inspection activities may be needed to provide the reasonable assurance that the intended function of below-grade FP piping will be maintained consistent with your current licensing basis for the extended operation.

Response to RAI B.3.12.2-6
The environmental conditions of the interior surface of the below-grade fire protection piping are exactly the same as that of the above-grade fire protection piping – stagnant lake water. The material conditions of the below-grade fire protection piping are different than that of the above-grade fire protection piping. The below-grade fire protection piping is cement-lined, providing it with an added feature to prevent the loss of material of the base metal due to corrosion. The cement lining also prevents internal buildup of turbucles that would contribute to degradation of the pipe flow characteristics. In addition to the inspection activities, the testing features of the *Fire Protection Program* described in Section B.3.12.2 of the Application perform testing on the below-grade, as well as above-ground, portion of the system to provide assurance that the entire system can perform its intended function.

Additionally, Duke has performed intrusive visual inspections of the internal surfaces of the underground cement-lined piping during maintenance or modification work. The condition of the piping is excellent. The internal lining is intact, ensuring the integrity of the base metal.

B.3.15 Fluid Leak Management Program

RAI B.3.15-1

The staff observed that there is no mention of strategies that address leak management for component segments that are not accessible to visual inspection (monitoring and trending). The staff and applicant discussed this observation during a conference call on October 25, 2001. A summary of the conference call was issued on December 12, 2001. During the conference call, the applicant indicated that the condition of material in accessible areas is considered indicative of material in inaccessible areas. The staff requests the applicant to discuss any provisions for inspecting potentially vulnerable, inaccessible locations for boric acid corrosion that were documented in their response to Generic Letter 88-05.

Response to RAI B.3.15-1

The staff request points to the need to review the specific Duke response to Generic Letter 88-05 for both McGuire and Catawba. Duke provided two responses to Generic Letter 88-05. [References 1 and 2 below] These responses covered Oconee, McGuire and Catawba and are dated May 23, 1988 and August 1, 1988, respectively. A review of the details in these letters identified no specific discussion regarding inspecting potential vulnerable, inaccessible locations for boric acid corrosion.

The August 1, 1988 response does discuss the fact that "...where it is deemed necessary a review of containment systems will be conducted to ensure that all potential leak locations have been identified." An understanding of these leak locations, whether accessible or inaccessible, was used in the establishment of the initial program in 1989. Duke also notes that additional operating experiences in the 1990's resulted in expansion of the program beyond containment systems to include systems containing dissolved boric acid in locations outside of containment that could possibly leak and lead to boric acid wastage. Because the *Fluid Leak Management Program* relies on surveillance to identify evidence of leakage and the surveillances have been designed with an understanding of potential leak locations, the condition of areas accessible for surveillance will be indicative of material in inaccessible areas.

1. H. B. Tucker (Duke) letter dated May 23, 1988 to Document Control Desk (NRC), *Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants (Generic Letter 88-05).* Oconee Nuclear Station, Docket Nos. 50-269, -270 and -287; McGuire Nuclear Station, Docket Nos. 50-369 and 370; and Catawba Nuclear Station, Docket Nos. 50-413 and 414.

2. H. B. Tucker (Duke) letter dated August 1, 1988 to Document Control Desk (NRC), *Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants*

(Generic Letter 88-05). Oconee Nuclear Station, Docket Nos. 50-269, -270 and -287; McGuire Nuclear Station, Docket Nos. 50-369 and 370; and Catawba Nuclear Station, Docket Nos. 50-413 and 414.

B.3.16 Galvanic Susceptibility Inspection

RAI B.3.16-1

The LRA states that the galvanic susceptibility inspection will involve inspection of a select set of carbon steel-stainless steel couples at each site (monitoring and trending). Since the galvanic susceptibility inspections are one-time inspections of a given sample that are intended to provide objective evidence that the applicable aging effects are being adequately managed, explain how the sample size will be selected in order to ensure that the inspection population is representative for all systems listed in the galvanic susceptibility inspection program scope.

The list of systems includes nuclear service water, which is large, complex, usually with multiple materials, subject to a variety of environments, that may change over time, including flowing and stagnant water, microbiological species, etc. The mechanisms include localized (e.g., pitting) and uniform corrosion. Given these complexities, justify that limiting the proposed inspections to carbon-stainless steel couples provides sufficient evidence in regards to the potential aging degradation of all galvanic couples in nuclear service water and other systems.

Response to RAI B.3.16-1

At the time of the one-time inspection, Duke will determine the set of carbon steel-stainless steel couples exposed to raw water. From that set, the sample population for inspection will be chosen using criteria such as flow regime (stagnant, low flow, and full flow), geometry (area ratios), and length of service. The sample population will include couples from the different flow regimes that have been in service the longest. Geometry considerations that aid galvanic corrosion will also be considered as well as for ease of inspection. Accessibility and radiological concerns will also be factored in when selecting locations for inspection.

The systems within the scope of *Galvanic Susceptibility Inspection* contain a large number of galvanic couples. Inspection of a representative sample of the different couple combinations is not practical. Since this inspection is to be performed near the end of the current license, Duke decided the inspection should focus on the couples most likely to exhibit galvanic corrosion if it is occurring. Duke determined that a representative sample carbon steel-stainless steel couples should be inspected because they had the largest separation on the galvanic series which equates to a higher likelihood of galvanic corrosion occurring. The results of these inspections will be applied to the other galvanic couples that are closer together on the galvanic series which would lead to a less aggressive corrosion rate and may not result in a loss of the component intended function during the period of extended operation.

RAI B.3.16-2

The LRA describes the acceptance criterion for the galvanic susceptibility inspections as "no unacceptable loss of material that could result in a loss of the component intended function(s) as determined by engineering evaluation." Describe the criteria that will be used to define "unacceptable loss of material" and how the acceptance criteria will ensure that the component functions are maintained under all CLB design loading conditions during the period of extended operation. Also, describe the analysis methodology that will be used to evaluate the inspection results against the acceptance criteria.

Response to RAI B.3.16-2

The acceptance criteria for the *Galvanic Susceptibility Inspection* are no unacceptable loss of material that could result in a loss of the component intended function(s). If evidence of loss of material is observed during the initial inspection, a problem report will be developed in accordance with Problem Investigation Process of Nuclear System Directive 208. The Problem Investigation Process is a formalized process for documenting engineering evaluations of plant problems that would include the assessment of the severity of the observed degradation, the need for corrective actions, the need for further inspections of other locations, and the need for future inspections or programmatic oversight. Criteria such as ASME Code requirements, additional inspection results, and operating experience may be used to assess the severity of the degradation and the need for corrective actions. Any criteria or analysis methods involved in determining the severity of the degradation and the need for corrective action will be developed at the time of the evaluation and will be a part of the problem report. Duke believes it is premature to specify analysis methodology and the actual criteria or analysis methods for determining severity and the need for corrective actions for an inspection that will occur 15 to 20 years from now.

RAI B.3.16-3

The scope of the galvanic susceptibility inspection program is indicated to include all galvanic couples exposed to gas, unmonitored treated water, and raw water environments in the McGuire and Catawba systems listed (scope). However, the proposed implementation involves only measurements on carbon steel-stainless steel couples (parameters monitored or inspected), based on an assumption that this couple represents a worst case, based on expectations from the galvanic series (monitoring and trending). The relative position in the series can shift, depending on specific environments, and the position of stainless steel in the series depends on whether the material is active or passive. Additionally, copper alloys are listed as relevant materials. Could the CS/SS couple measurements provide favorable results that fail to address the galvanic phenomena that may be degrading other materials?

Response to RAI B.3.16-3

For galvanic corrosion to occur, dissimilar metals must be exposed to an electrolyte. The galvanic couples within the scope of the *Galvanic Susceptibility Inspection* are exposed to one of the following three electrolytes: nitrogen gas, unmonitored treated water, and raw water. Nitrogen gas by itself is a poor electrolyte. The addition of water vapor increases its conductivity provided that it has the necessary contaminants. The water vapor is from the Reactor Coolant System and is expected to contain minimal levels of contaminants. As result, Duke believes that the nitrogen gas environment with water vapor is a poor electrolyte.

The unmonitored treated water environment is from several borated and treated water systems whose environments are maintained by the *Chemistry Control Program* to ensure the contaminants that make a solution a good conductor are at a minimal level. Considering the location of this unmonitored treated water environment, Duke believes the environment has a higher conductivity than the systems it came from but not to the point of making it a great electrolyte. As a result, Duke believes that the unmonitored treated water environment is a fair electrolyte.

The raw water environment is from Lake Wylie at Catawba and Lake Norman at McGuire. Electrical conductivity measurements for Lake Wylie are around 120 μS/cm and 70 μS/cm for Lake Norman. Treated water systems are usually below 10 μS/cm. As a result, Duke believes that the raw water environment is the best electrolyte and that carbon steel-stainless steel couples exposed to raw water are the most likely locations to inspect to determine whether or not galvanic corrosion is occurring. These results would be applied to the other couples where galvanic corrosion is expected to be less aggressive.

Since all the environments involve water with various levels of contaminants, shifting of the metals on the galvanic series such that stainless steel would waste in a copper-stainless steel or

carbon steel-stainless steel couple does not seem likely. As a result, Duke does not believe that carbon steel-stainless steel couple measurements will provide favorable results that fail to address the galvanic phenomena that may be degrading the other materials.

RAI B.3.16-4

The LRA states that the parameter inspected by the galvanic susceptibility inspection program is pipe wall thickness (parameters monitored or inspected) and inspections will be performed using a volumetric examination technique. As an alternative, visual examination will be used should access to internal surfaces become available (monitoring and trending). The staff and applicant discussed this observation during a conference call on October 25, 2001. A summary of the conference call was issued on December 12, 2001. During the conference call the applicant indicated that their intent was not to substitute a volumetric test with a visual inspection. The applicant acknowledged that a visual inspection does not provide the same level of confidence that a volumetric examination provides. The staff is satisfied with this response. However, since the LRA states that a visual inspection could be used as an alternative to volumetric testing, the staff requests the applicant to clarify the statement in the LRA.

Response to RAI B.3.16-4

Duke does not intend to <u>substitute</u> a volumetric test with a visual inspection. Duke's intention is to <u>supplement</u> volumetric tests with visual inspections should access to internal surfaces become available.

McGuire UFSAR Supplement 18.2.12 and Catawba UFSAR Supplement 18.2.11 will be revised as follows:

Monitoring & Trending – revise second sentence to read as follows: "Visual examination will also be used should access to internal surfaces become available."

B.3.17 Heat Exchanger Activities

RAI B.3.17-1

Are the flow rates in the heat exchanger system being measured to ensure that the flow rates are below the threshold of susceptibility for flow-induced corrosion for the materials in the Catawba and McGuire heat exchangers?

Response to RAI B.3.17-1

During the aging management review process, when determining aging effects that are applicable to a particular material/environment combination, a consideration of the normal or design flow rate is considered as part of the environment that the material experiences. For heat exchangers, flow-induced corrosion was considered as a potential aging effect for those materials that are susceptible. Normal or design velocities were reviewed for each heat exchanger to determine whether flow-induced corrosion is applicable. Flow-induced corrosion is not an applicable aging effect for any heat exchanger subject to aging management review.

B.3.22 Liquid Waste System Inspection

RAI B.3.22-1

In section B.3.22 of the LRA, under monitoring & trending, the applicant stated that the selection of the specific areas for inspection for the system material/environment combinations will be the responsibility of the system engineer. Discuss the selection criteria that will be used by the system engineer for the inspection of the specific areas.

Response to RAI B.3.22-1

The *Liquid Waste System Inspection* will inspect locations in areas of low or stagnant flow where contaminants are likely to collect and concentrate to create a corrosive environment. In addition, components around the Catawba Liquid Radwaste System sumps that are exposed to raw water environments will also be inspected. Selection criteria such as component orientation, operating temperature, proximity to hot equipment, and previous operating experience will be used to determine the inspection locations in the above areas. Accessibility and radiological concerns will also be considered in the selection of inspection sites if no one site is distinguishable from the others.

RAI B.3.22-2
The acceptance criteria for the liquid waste system inspection program are: (1) no unacceptable loss of material or cracking for stainless steel components, and (2) no loss of material for carbon steel and cast iron components, that could result in a loss of the component intended function(s) as determined by engineering evaluation. Describe the criteria for (1) assessing the severity of the observed degradations and (2) determining whether corrective action is necessary.

Response to RAI B.3.22-2
The acceptance criteria for the *Liquid Waste System Inspection* are no unacceptable loss of material that could result in a loss of the component intended function(s). If evidence of loss of material is observed during the initial inspection, a problem report will be developed in accordance with Problem Investigation Process of Nuclear System Directive 208. The Problem Investigation Process is a formalized process for documenting engineering evaluations of plant problems that would include the assessment of the severity of the observed degradation, the need for corrective actions, the need for further inspections of other locations, and the need for future inspections or programmatic oversight. Criteria such as ASME Code requirements, additional inspection results, and operating experience may be used to assess the severity of the degradation and the need for corrective actions. Any criteria involved in determining the severity of the degradation and the need for corrective action will be developed at the time of the evaluation and will be a part of the problem report. Duke believes it is premature to specify the actual criteria for determining severity and the need for corrective actions for an inspection that will occur 15 to 20 years from now.

B.3.24 Preventive Maintenance Activities

RAI B.3.24-1

The LRA describes the scope of the preventive maintenance activities and states that it is applicable to several systems (diesel generator fuel oil, exterior fire protection, interior fire protection, nuclear service water system and standby shutdown system) in addition to the intake and discharge piping of the condenser circulating water system. The various elements of the aging management program (parameters monitored or inspected, monitoring and trending, acceptance criteria and operating experience) address only the condenser piping with no reference to the other systems (e.g. underground portion of the emergency diesel generator and standby shutdown diesel generator fuel oil storage tanks and stainless steel piping and valves) that are within the stated scope of the preventative maintenance activities. Describe how the aging management program is implemented for these other systems, which may consist of smaller diameter piping. Describe operating experience for these systems and the experience to date in application of the preventative maintenance activities to these systems.

Response to RAI B.3.24-1

As stated in Appendix B of the Application, the *Preventive Maintenance Activities – Condenser Circulating Water System Internal Coatings Inspection* has two purposes. The first purpose is to manage loss of material of the internal surfaces of the large diameter intake and discharge piping in the Condenser Circulating Water System only. The second purpose of this activity is to manage loss of material and cracking of the external surfaces of components in the underground environment by providing symptomatic evidence of the condition of the piping external surfaces. To accomplish the second purpose, the activity is performed on the large diameter intake and discharge piping in the Condenser Circulating Water System with the results applied to the other systems listed in the **Scope** program attribute. During plant construction, all buried components were coated, wrapped, and backfilled in a consistent manner specified by engineering. As a result, Duke believes the results of the inspection on the Condenser Circulating Water System are applicable to the other systems with license renewal buried components. Approximately eighty percent (80%) of the total buried surface area within the scope of license renewal is inspected by this preventive maintenance activity. The results of the inspection will be applied to the remaining twenty percent (20%) residing in the other systems listed in the **Scope** program attribute.

The operating experience presented in Appendix B of the Application for the *Preventive Maintenance Activities – Condensers Circulating Water System Internal Coatings Inspection* indicates that the external coating is in good condition and still performing its function of protecting the external surfaces of buried components. Since all buried components were coated, wrapped, and backfilled in a consistent manner, the operating experience suggests that the

external coating in the other systems listed in the **Scope** program attribute is also in good condition and still performing its function.

RAI B.3.24-2
Raw water carries with it sediments and debris that deposit on the bottom of the pipes. If areas of the pipe are obscured by sediments and debris, the coating inspection activities would be compromised (monitoring and trending). Are areas of the pipes obscured by deposits? If so, are special measures applied to facilitate the coating inspection?

Response to RAI B.3.24-2
The areas inspected by this preventive maintenance activity are normally in service during plant operation. As a result, debris or sediment on the bottom of the pipe has not been observed. Any debris and sediment that obscures the coating will be removed prior to the inspection.

RAI B.3.24-3
The acceptance criteria for the preventive maintenance activities are no visual indications of coating defects including but not limited to blistering, peeling, or missing coatings that reveal corrosion of the piping as determined by Engineering. Describe the criteria for (1) assessing the severity of the observed degradations and (2) determining whether corrective action is necessary.

Response to RAI B.3.24-3
The acceptance criteria for the *Preventive Maintenance Activities – Condenser Circulating Water System Internal Coating Inspection* are no visual indications of coating defects including but not limited to blistering, peeling, or missing coatings that reveal corrosion of the piping. If evidence of coating defects is observed during the inspection, a problem report will be developed in accordance with Problem Investigation Process of Nuclear System Directive 208. The Problem Investigation Process is a formalized process for documenting engineering evaluations of plant problems that would include the assessment of the severity of the observed degradation, the need for corrective actions, the need for further inspections of other locations, and the need for future inspections or programmatic oversight. Criteria such as wall loss of the underlying metal, service life of the coating, root-cause analysis of the coating failure, and operating experience could be used to assess the severity of the degradations and the need for corrective actions. Any criteria involved in determining the severity of the degradation and the need for corrective action will be developed at the time of the evaluation and will be a part of the problem report.

B.3.28 Selective Leaching Inspection

RAI B.3.28-1

The LRA states that a Brinnell hardness test or an equivalent test will be performed on one cast iron pump casing in the exterior fire protection system at each site and that this test will be indicative of selective leaching for all cast iron components in all the systems listed in the selective leaching inspection program scope (monitoring and trending). Provide the basis for concluding that the inspection of a single pump casing in the exterior fire protection system at each site will be indicative of the state of selective leaching in all cast iron components in all raw water systems.

Response to RAI B.3.28-1

The specific material types of gray cast iron and yellow brass are susceptible to loss of material due to selective leaching. For the cast iron components within the scope of the *Selective Leaching Inspection*, Duke was not able to confirm that these components were not constructed of gray cast iron. Vendor documents noted that the material of construction was cast iron. Duke believes that proper material selection was done by the vendor for the given design conditions, does not believe selective leaching is occurring, and has no operating experience to suggest selective leaching is occurring in these components. Since the aging effect could not be absolutely ruled out, Duke decided an inspection was warranted. Therefore, Duke proposed the *Selective Leaching Inspection* to confirm our position.

The cast iron components within the scope of this inspection are pipe, pump casings, standpipes, and valve bodies. The pump casings reside in the Conventional Wastewater Treatment, Diesel Generator Room Sump Pump, Groundwater Drainage, and Exterior Fire Protection Systems. Cast iron pipe, standpipe, and valve bodies are found in the Exterior Fire Protection System.

The Conventional Wastewater Treatment and Diesel Generator Room Sump Pump Systems are sump components that are periodically wetted and dried with a raw water environment. The Groundwater Drainage System collects spring water for disposal. The Exterior Fire Protection System contains stagnant raw water from Lake Norman (McGuire) or Lake Wylie (Catawba).

Duke believes the environment in the Exterior Fire Protection System pump casings is the most aggressive for promoting selective leaching and bounds the environments of the other pump casings and is equivalent to the environment of the valve bodies. Inspection of the Exterior Fire Protection System pump casings has a higher likelihood of identifying selective leaching if it is occurring. The results of the pump body inspection would be applied to the remainder of the cast iron components. Due to the small number of components involved and the likelihood that the

components are not constructed from a susceptible material, Duke believes that inspection of one pump casing at each site bounds the other components and is sufficient.

RAI B.3.28-2

The LRA states that Brinnell hardness tests or equivalent tests will be performed on a sample of brass valves at each site in the interior fire protection system and that these valves selected for inspection should be (interpreted to mean will be) those that are continuously exposed to stagnant or low flow raw water environments. The LRA also states that the results of this inspection will be applied to the brass components exposed to raw water environments in the remaining systems listed in the selected leaching program scope (monitoring and trending). Describe the analyses or evaluations that will be used to determine the sample size. Also, provide a basis for concluding that brass valve bodies in the interior fire protection system will be indicative of the state of selective leaching in all brass components in all raw water systems.

Response to RAI B.3.28-2

The total number of brass valves exposed to raw water will be determined prior to the inspection. A subset for inspection will be determined by focusing on those valves exposed to low flow or stagnant conditions. This subset may be further narrowed by component geometry, location/component operating experience, length of service, accessibility, and radiological concerns.

The brass components within the scope of the *Selective Leaching Inspection* are in the Exterior Fire Protection, Interior Fire Protection, and Nuclear Service Water Systems. Brass valves and sprinklers are found in the Exterior Fire Protection System and the Interior Fire Protection System. Additionally, a reciprocating charging pump fluid drive oil cooler tubesheet in the Nuclear Service Water System is brass. These systems contain raw water from Lake Norman (McGuire) and Lake Wylie (Catawba). As a result, Duke believes that the results of an inspection of a sample of brass valves in low flow or stagnant conditions at each site would be indicative of the condition of the remaining brass components in these systems.

RAI B.3.28-3

The LRA describes the acceptance criterion for the selective leaching inspections as "no unacceptable loss of material that could result in a loss of the component intended function(s) as determined by engineering evaluation." Describe the criteria that will be used to define "unacceptable loss of material" and how the acceptance criteria will ensure that the component functions are maintained under all CLB design loading conditions during the period of extended operation. Also, describe the analysis methodology that will be used to evaluate the inspection results against the acceptance criteria.

Response to RAI B.3.28-3

The acceptance criteria for the *Selective Leaching Inspection* are no unacceptable loss of material that could result in a loss of the component intended function(s). If evidence of loss of material is observed during the initial inspection, a problem report will be developed in accordance with Problem Investigation Process of Nuclear System Directive 208. The Problem Investigation Process is a formalized process for documenting engineering evaluations of plant problems that would include the assessment of the severity of the observed degradation, the need for corrective actions, the need for further inspections of other locations, and the need for future inspections or programmatic oversight to ensure that the component functions are maintained under all CLB design loading conditions during the period of extended operation. Criteria or analysis methods that could be used might include ASME Code requirements, additional inspection results, and operating experience to assess the severity of degradation and need for corrective action. Any criteria or analysis methods involved in determining the severity of the degradation and the need for corrective action will be developed at the time of the evaluation and will be a part of the problem report. Duke believes it is premature to specify the actual criteria or analysis methods for determining severity and the need for corrective actions for an inspection that will occur 15 to 20 years from now.

B.3.29 Service Water Piping Corrosion Program

RAI B.3.29-1

The LRA describes the parameters monitored or inspected as part of the service water piping corrosion program to be wall thickness measurements as an indicator of loss of material (monitoring & trending). What methods (e.g., codes/standards or industry guidelines) are used to select the UT procedures and the number/grid of locations to be inspected?

Response to RAI B.3.29-1

The methods used to select the ultrasonic testing procedures, including grid size and the number of locations to be inspected, were developed as a department initiative among Duke's three nuclear sites. Original efforts to define inspection procedure details were made as a part of Duke's response to NRC Generic Letter 89-13. Initial engineering studies provided the foundation for the program. Subsequent improvements to the program based on actual field experience ensure that inspection locations represent all piping, including all pipe size ranges and flow regimes. Duke has been involved in industry efforts sponsored through EPRI to address the service water corrosion issue. Because the corrosion phenomena is slow-acting and very water-quality specific, only limited industry guidance has been available to complement the Duke program basis.

RAI B.3.29-2
The LRA describes the scope of the service water piping corrosion program and states that it is applicable to several systems (nuclear service water, containment spray, diesel generator cooling water, etc.). The description of operating experience in the LRA makes only a general statement of typical corrosion rates, which range from 3 to 5 mills per year. Provide examples for corrosion rates for specific systems, and examples of how measurements have been used to determine frequencies of re-inspection and to expand the number of locations for wall thickness measurements.

Response to RAI B.3.29-2
A review of over one hundred inspection locations in the Nuclear Service Water System indicates that the worst locations experience corrosion rates of approximately 3-5 mils per 18-month operating cycle, based on the low band averages (lowest average wall thickness in a circumferential band) of the inspection locations. Other locations, such as stagnant locations, indicate much lower corrosion rates. Review of inspection locations in the Catawba Interior Fire Protection System indicates corrosion rates of approximately 3-5 mils per 18-month operating cycle. Because this system is stagnant, very low corrosion rates have been experienced. The inspection locations of the Interior Fire Protection System are applicable to the Exterior Fire Protection System. See response to RAI B.3.12.2-6.

Inspection locations do not exist in every system for which the *Service Water Piping Corrosion Program* is credited for managing aging for license renewal. Inspection locations do exist that represent all types of piping, including (a) upstream and downstream of major pieces of equipment, (b) every pipe size, (c) different flow regimes and (d) each stress analysis math model. Inspection of all these location types provides relevant findings for locations with similar conditions across all the plant raw water systems. For example, the inspection locations of the Nuclear Service Water System are applicable to all of the heat exchangers of the Containment Spray System, Control Area Chilled Water System, Diesel Generator Cooling Water System, and the Diesel Generator Engine Starting Air System (CNS only) because the Nuclear Service Water System supplies these heat exchangers. It is the Nuclear Service Water side of the heat exchanger that the program is credited for managing.

The frequency of reinspection is determined using the calculated corrosion rate. Corrosion rate, and thus reinspection frequency, is determined by comparing the low band average (lowest average wall thickness in a circumferential band) of the inspection location against the nominal wall thickness and averaged against the number of operating cycles. This value is compared against the minimum allowed wall thickness to determine the remaining life (approximate replacement cycle). The intent of the program is to monitor and inspect well before action such as replacement is required.

For example, on a Catawba Nuclear Service Water inspection location of an 18"pipe with nominal wall thickness of 0.375 inches, the low band average of the inspection was 0.324 inches during cycle 12. The corrosion rate is 0.375 inches minus 0.324 inches, divided by 12 operating cycles, conservatively equal to .005 inches. Determination of remaining life (time to reach minimum allowable wall thickness) is calculated by subtracting the minimum wall of 0.250 inches from the actual wall of 0.324 inches and dividing that value by the corrosion rate of 0.005 inches per cycle. The result yields a remaining life of (conservatively) 14 cycles, or end of life during cycle 26. The inspection location would be scheduled for reinspection well before cycle 26, perhaps at cycle 20.

Sample expansion is rarely required due to the number of inspection locations already in the program. There are data points representing all piping: (a) upstream and downstream of major pieces of equipment, (b) every pipe size, (c) different flow regimes and (d) each stress analysis math model. Sample expansion is performed in some instances where one inspection location is used as a representative location of both trains or units to include inspection of the opposite train or other unit.

B.3.32 Sump Pump Inspection

RAI B.3.32-1

The acceptance criterion for the sump pump inspection program is no unacceptable loss of material that could result in the loss of the component intended function(s), as determined by engineering evaluation. Describe the criteria for (1) assessing the severity of the observed degradations and (2) determining whether corrective action is necessary.

Response to RAI B.3.32-1

The acceptance criteria for the *Sump Pump Inspection* are no unacceptable loss of material that could result in a loss of the component intended function(s). If evidence of loss of material is observed during the initial inspection, a problem report will be developed in accordance with Problem Investigation Process of Nuclear System Directive 208. The Problem Investigation Process is a formalized process for documenting engineering evaluations of plant problems that would include the assessment of the severity of the observed degradation, the need for corrective actions, the need for further inspections of other locations, and the need for future inspections or programmatic oversight. Criteria such as ASME Code requirements, results from additional inspections, and operating experience may be used to assess the severity of the degradation and the need for corrective action. Any criteria involved in determining the severity of the degradation and the need for corrective action will be developed at the time of the evaluation and will be a part of the problem report. Duke believes it is premature to specify the actual criteria for determining severity and the need for corrective actions for an inspection that will occur 15 to 20 years from now.

B.3.34 Treated Water Systems Stainless Steel Inspection

RAI B.3.34-1

The LRA states that because of the higher starting level of contaminants in the Catawba drinking water system, cracking or loss of material is more likely to occur in the Catawba drinking water system than in the containment valve injection water or solid radwaste systems. Therefore, the inspection results from the Catawba drinking water system are proposed to be bounding (monitoring & trending). Three factors have been identified that promote stress corrosion cracking of stainless steels: (1) metallurgical (e.g., sensitization), (2) stress level, and (3) environmental (e.g., level of contaminants). The basis for the proposed Catawba treated water systems stainless steel inspection program only focuses on one of these three factors, namely environment. Discuss how the metallurgical and stress level factors were considered in the system susceptibility comparisons performed by Duke or, justify why these factors were not considered.

Response to RAI B.3.34-1

The three factors required to promote stress corrosion cracking of stainless steel are (1) metallurgical (e.g., sensitization), (2) stress level, and (3) environmental (e.g., level of contaminants). While the resulting selection of the Catawba Drinking Water System for the *Treated Water Stainless Steel Inspection* focuses on its distinguishing environmental parameter, all three of the parameters were considered among each of the three systems before this decision was made.

When considering sensitization, Duke believes that as a result of its controlled welding program the degree of sensitization is consistent throughout each of the three stainless steel systems. No distinction can be made for this parameter among the three systems.

Stress in system components results from (1) applied loads, (2) residual stresses as a result of cold work, welding or other material processing, or (3) a combination of the two. When considering stress level, these various aspects of stress were considered for the three systems falling within the *Treated Water Stainless Steel Inspection.* Because each of the systems operates at low pressure and low temperature, no distinction can be made concerning applied loads. Additionally, construction of the systems was done under the controlled welding program, meaning no distinction can be made concerning residual stresses. Overall, no distinction can be made for the stress parameter among the three systems.

Environmental effects are the third parameter playing a role in promoting stress corrosion cracking. Dissolved oxygen and halogens are contributors to stress corrosion cracking of stainless steel. For the three Catawba systems within the scope of this one-time inspection, the

Drinking Water System has the highest contaminant levels. This difference is the only clear cut distinction among the systems. The Containment Valve Injection Water System is filled with demineralized water. The Solid Radwaste System receives borated water from plant systems. Demineralized water and borated water used at Catawba contain lower levels of the contaminants known to be a concern for stress corrosion cracking than the Drinking Water System.

While Duke does not believe that loss of material and cracking of stainless steel components within these systems is occurring, the aging effects could not absolutely be ruled out. Duke decided that an inspection was warranted and will focus on the Catawba Drinking Water System as the leading indicator for the *Treated Water Stainless Steel Inspection.*

RAI B.3.34-2

The LRA describes the acceptance criterion for the treated water systems stainless steel inspection program as no unacceptable loss of material that could result in a loss of the component intended function(s) as determined by engineering evaluation (acceptance criteria). Describe the criteria that will be used to define "unacceptable loss of material" and how these acceptance criteria will ensure that the component functions are maintained under all CLB design loading conditions during the period of extended operation. Also, describe the analysis methodology that will be used to evaluate the inspection results against the acceptance criteria.

Response to RAI B.3.34-2

The acceptance criteria for the *Treated Water Systems Stainless Steel Inspection* are no unacceptable loss of material or cracking that could result in a loss of the component intended function(s). If evidence of loss of material or cracking is observed during the initial inspection, a problem report will be developed in accordance with Problem Investigation Process of Nuclear System Directive 208. The Problem Investigation Process is a formalized process for documenting engineering evaluations of plant problems that would include the assessment of the severity of the observed degradation, the need for corrective actions, the need for further inspections of other locations, and the need for future inspections or programmatic oversight to ensure that the component functions are maintained under all CLB design loading conditions during the period of extended operation. Criteria or analysis methods that could be used might include ASME Code requirements, additional inspection results, and operating experience to assess the severity of degradation and need for corrective action. Any criteria or analysis methods involved in determining the severity of the degradation and the need for corrective action will be developed at the time of the evaluation and will be a part of the problem report. Duke believes it is premature to specify the actual criteria or analysis methods for determining severity and the need for corrective actions for an inspection that will occur 15 to 20 years from now.

B.3.36 Waste Gas System Inspection

RAI B.3.36-1

In section B.3.36 of the LRA, under Monitoring & Trending:

(a) The applicant stated that the waste gas system inspection will use a volumetric technique to inspect four sets of material/environment combinations. Describe the four sets of material/environment combinations.

(b) The applicant stated that the selection of the specific areas for inspection for the above material/environment combinations will be the responsibility of the system engineer. Discuss the selection criteria that will be used by the system engineer for the inspection of the specific areas.

(c) In items (1) through (4), the applicant described the inspection criteria for cases where no parameters are known that would distinguish the susceptible locations at each site. Describe the inspection criteria, including the sample size, that will be used for those cases where the parameters are known that would distinguish the susceptible locations at each site.

Response to RAI B.3.36-1

(a) As stated on page B.3.36-2 of the Application, the material/environment combinations to be volumetrically inspected are as follows:

- Brass/Unmonitored Treated Water
- Carbon Steel/Unmonitored Treated Water
- Stainless Steel/Unmonitored Treated Water
- Carbon Steel/Nitrogen Gas

Unmonitored treated water is treated water from other systems that has entered the Waste Gas System but is not monitored and controlled by the *Chemistry Control Program*. The nitrogen gas environment is primarily nitrogen gas with water vapor and fission product gasses.

(b) The selection criteria for the areas where inspection locations should be chosen are stated on page B.3.36-2 of the Application. Criteria such as component geometry, operating temperatures, and operating experience could be used to determine the actual inspection locations. Accessibility and radiological concerns will also be considered when selecting inspection locations if no parameters exist to distinguish one inspection location over another. Any criteria involved in determining inspection locations will be developed at the time the inspection plan is developed. Duke believes it is premature to specify the actual criteria for determining inspection locations for an inspection that will occur 15 to 20 years from now.

(c) Criteria such as component geometry, operating temperatures, system operation, and previous operating experience could be used to determine the most susceptible locations in the areas noted in Section B.3.36 of Appendix B of the Application. Application of the criteria would produce a set of most susceptible locations for inspection. Accessibility and radiological concerns will be considered in the selection of inspection sites from the total population. Any criteria involved in determining inspection locations will be developed at the time the inspection plan is developed. Duke believes it is premature to specify the actual criteria for determining inspection locations for an inspection that will occur 15 to 20 years from now.

RAI B.3.36-2
The acceptance criteria for the waste gas system inspection program are no unacceptable loss of material or cracking that could result in a loss of the component intended function(s) as determined by engineering evaluation. Describe the criteria for (1) assessing the severity of the observed degradations and (2) determining whether corrective action is necessary.

Response to RAI B.3.36-2
The acceptance criteria for the *Waste Gas System Inspection* are no unacceptable loss of material or cracking that could result in a loss of the component intended function(s). If evidence of loss of material or cracking is observed during the initial inspection, a problem report will be developed in accordance with Problem Investigation Process of Nuclear System Directive 208. The Problem Investigation Process is a formalized process for documenting engineering evaluations of plant problems that would include the assessment of the severity of the observed degradation, the need for corrective actions, the need for further inspections of other locations, and the need for future inspections or programmatic oversight. Criteria such as ASME Code requirements, additional inspection results, and operating experience may be used to assess the severity of degradation and need for corrective action. Any criteria involved in determining the severity of the degradation and the need for corrective action will be developed at the time of the evaluation and will be a part of the problem report. Duke believes it is premature to specify the actual criteria for determining severity and the need for corrective actions for an inspection that will occur 15 to 20 years from now.

Attachment 4
Application to Renew the Operating Licenses of
McGuire Nuclear Station and Catawba Nuclear Station
Responses to NRC Requests for Additional Information
NRC Letters dated January 23, 28, and 28, 2002

LIST OF COMMITMENTS

List of Commitments

1. The response to this RAI is in preparation and will be provided on or before April 15, 2002. (Response to RAI 3.3-1)

2. The response to this RAI is in preparation and will be provided on or before April 15, 2002. (Response to RAI 3.3-2)

3. For the McGuire UFSAR Supplement Section 18.2.13.4, the last sentence in the paragraph will be revised to read as follows:

   > The *Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program* is credited for managing loss of material or fouling for admiralty brass, carbon steel, copper-nickel alloy, and stainless steel materials.

   (Response to RAI 3.3.9-1)

4. For the Catawba UFSAR Supplement Section 18.2.12.4, the last sentence in the paragraph will be revised to read as follows:

   > The *Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program* is credited for managing loss of material or fouling for admiralty brass, carbon steel, copper-nickel alloy, and stainless steel materials.

   (Response to RAI 3.3.9-1)

5. Section 18.2.12.5 of the Catawba UFSAR Supplement is in error and will be revised to read as follows:

   > 18.2.12.5 DIESEL GENERATOR ENGINE STARTING AIR
   >
   > The purpose of the *Heat Exchanger Preventive Maintenance Activities – Diesel Generator Engine Starting Air* is to manage loss of material for parts of the diesel generator engine starting air aftercoolers exposed to raw water. The *Heat Exchanger Preventive Maintenance Activities – Diesel Generator Engine Starting Air* is a condition monitoring program that monitors specific component parameters to detect the presence and assess the extent of material loss that can affect the pressure boundary function. The program is credited with managing loss of material for carbon steel and stainless steel.

   (Response to RAI 3.3.24-3)

6. The response to RAI 3.2-1 is in preparation and will be provided on or before April 15, 2002. (Response to RAI 3.2-1)

7. The summary description of the *Chemistry Control Program* is contained in McGuire UFSAR Supplement Section 18.2.4 and Catawba UFSAR Supplement Section 18.2.4. The second sentence of each summary will be revised to read as follows:

This program manages the relevant conditions that lead to the onset and propagation of loss of material, cracking, and fouling which could lead to a loss of structure or component intended functions.

(Response to RAI B.3.6-1)

8. The McGuire UFSAR Supplement Section 18.2.8 will be revised to read as follows:

Elements of the *Fire Protection Program* that serve to manage aging are implemented in accordance with Selected Licensee Commitments (See Table 18-1). The integrity of the sprinkler branch lines is assured by sprinkler flow tests performed by procedure every 18 months. Additionally, fouling of sprinkler branch lines that do not receive flow during periodic testing will be managed. Since these lines do not receive flow, it is believed that they are less susceptible to fouling than the lines that receive flow during testing. To validate this belief, branch lines of a few representative sprinkler systems will be volumetrically examined. Subsequent examinations for the period of extended operation will be determined based on the initial examination results. For McGuire, this volumetric examination 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 Unit 1).

(Response to RAI B.3.12.2-4)

9. The Catawba UFSAR Supplement Section 18.2.8 will be revised to read as follows:

> Elements of the *Fire Protection Program* that serve to manage aging are implemented in accordance with Selected Licensee Commitments (See Table 18-1).
>
> Additionally, fouling of sprinkler branch lines that do not receive flow during periodic testing will be managed. Since these lines do not receive flow, it is believed that they are less susceptible to fouling than the lines that receive flow during testing. To validate this belief, branch lines of a few representative sprinkler systems will be volumetrically examined. Subsequent examinations for the period of extended operation will be determined based on the initial examination results.
>
> For Catawba, this volumetric examination will be completed following issuance of renewed operating licenses for Catawba Nuclear Station and by December 26, 2024 (the end of the initial license of Catawba Unit 1).

(Response to RAI B.3.12.2-4)

10. McGuire UFSAR Supplement 18.2.12 and Catawba UFSAR Supplement 18.2.11 will be revised as follows:

> **Monitoring & Trending** – revise second sentence to read as follows: "Visual examination will also be used should access to internal surfaces become available."

(Response to RAI B.3.16-4)