February 24, 2003

Mr. M. S. Tuckman
Executive Vice-President
Nuclear Generation
Duke Energy Corporation
P.O. Box 1006 EC07H
Charlotte, NC 28201-1006

SUBJECT: ERRATA TO LICENSE RENEWAL SAFETY EVALUATION REPORT FOR MCGUIRE, UNITS 1 AND 2, AND CATAWBA, UNITS 1 AND 2

Dear Mr. Tuckman:

By a letter dated June 13, 2001, Duke Energy Corporation (Duke) submitted an application to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the McGuire, Units 1 and 2, and Catawba, Units 1 and 2, operating licenses for up to an additional 20 years. On January 6, 2003, the NRC staff issued its safety evaluation report (SER) to document the findings of the safety review of the license renewal application (LRA) and supporting documentation for McGuire, Units 1 and 2, and Catawba, Units 1 and 2.

In Section 3.6.1.2.2 of the SER, the staff documented its evaluation of aging management programs identified in the LRA and in correspondence from Duke to manage the aging effects of accessible non-EQ insulated cables and connections caused by heat or radiation. Shortly after the SER was issued, the staff determined that it had not clearly documented its evaluation of the License Renewal Program for Non-EQ Neutron Flux Instrumentation Circuits (provided by Duke in a letter dated November 14, 2002) and the License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits (provided by letter dated November 21, 2002, to supercede the information provided in the letter dated November 14, 2002). Therefore, SER pages 3-434 and 3-435 were revised to clarify the staff's evaluation. This letter transmits the revised pages as well as subsequent pages in SER Section that were reformatted as a result of the changes to pages 3-434 and 3-435 (enclosed).

If you have any questions regarding this matter, please contact me at 301-415-1868.

Sincerely,

/***RA***/

Rani Franovich, Project Manager
License Renewal and Environmental Impacts Program
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

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

Enclosure: As stated

cc w/encl: See next page

Mr. M. S. Tuckman
Executive Vice-President
Nuclear Generation
Duke Energy Corporation
P.O. Box 1006 EC07H
Charlotte, NC 28201-1006

SUBJECT: ERRATA TO LICENSE RENEWAL SAFETY EVALUATION REPORT FOR MCGUIRE, UNITS 1 AND 2, AND CATAWBA, UNITS 1 AND 2

Dear Mr. Tuckman:

By a letter dated June 13, 2001, Duke Energy Corporation (Duke) submitted an application to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the McGuire, Units 1 and 2, and Catawba, Units 1 and 2, operating licenses for up to an additional 20 years. On January 6, 2003, the NRC staff issued its safety evaluation report (SER) to document the findings of the safety review of the license renewal application (LRA) and supporting documentation for McGuire, Units 1 and 2, and Catawba, Units 1 and 2.

In Section 3.6.1.2.2 of the SER, the staff documented its evaluation of aging management programs identified in the LRA and in correspondence from Duke to manage the aging effects of accessible non-EQ insulated cables and connections caused by heat or radiation. Shortly after the SER was issued, the staff determined that it had not clearly documented its evaluation of the License Renewal Program for Non-EQ Neutron Flux Instrumentation Circuits (provided by Duke in a letter dated November 14, 2002) and the License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits (provided by letter dated November 21, 2002, to supercede the information provided in the letter dated November 14, 2002). Therefore, SER pages 3-434 and 3-435 were revised to clarify the staff's evaluation. This letter transmits the revised pages as well as subsequent pages in SER Section that were reformatted as a result of the changes to pages 3-434 and 3-435 (enclosed).

If you have any questions regarding this matter, please contact me at 301-415-1868.

Sincerely,
/***RA***/
Rani Franovich, Project Manager
License Renewal and Environmental Impacts Program
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Docket Nos.: 50-369, 50-370, 50-413, and 50-414
Enclosure: As stated
cc w/encl: See next page
DISTRIBUTION:
See next page
1. Letter to M. Tuckman from R. Franovich:
2. Pages 3-433 through 3-454 of the SER Related to McGuire and Catawba License Renewal Application:

Document Name: C:\ORPCheckout\FileNET\ML030550775.wpd

OFFICE	PM:RLEP:DRIP	LA:RLEP:DRIP	TR:EEIB:DE	SC:RLEP:DRIP	PD:RLEP:DRIP
NAME	RFranovich	HBerilla	DNguyen	SLee	PTKuo
DATE	01/21/2003	01/22/2003	01/31 /2003	01/31/2003	02/24/2003

OFFICIAL RECORD COPY

DISTRIBUTION: Letter to Mr. Michael S. Tuckman, Dated: February 24, 2003

HARD COPY

RLEP RF
R. Franovich

E-MAIL:

PUBLIC
W. Borchardt
D. Matthews
F. Gillespie
RidsNrrDe
R. Barrett
E. Imbro
G. Bagchi
K. Manoly
W. Bateman
J. Calvo
C. Holden
P. Shemanski
H. Nieh
G. Holahan
H. Walker
S. Black
B. Boger
D. Thatcher
G. Galletti
C. Li
J. Moore
R. Weisman
M. Mayfield
A. Murphy
W. McDowell
S. Smith (Srs3)
T. Kobetz
R. Assa
C. Munson
RLEP Staff

R. Martin
C. Patel
R. Haag
C. Julian

McGuire & Catawba Nuclear Stations, Units 1 and 2

cc:

Ms. Lisa F. Vaughn
Legal Department (PBO5E)
Duke Energy Corporation
422 South Church St.
Charlotte, NC 28201-1006

County Manager of Mecklenburg County
720 East Fourth St.
Charlotte, NC 28202

Mr. Michael T. Cash
Regulatory Compliance Manager
Duke Energy Corporation
McGuire Nuclear Site
12700 Hagers Ferry Rd.
Huntersville, NC 28078

Anne Cottingham, Esquire
Winston and Strawn
1400 L Street, NW
Washington, DC 20005

Senior Resident Inspector
c/o U. S. Nuclear Regulatory
Commission
12700 Hagers Ferry Rd.
Huntersville, NC 28078

Mr. Peter R. Harden, IV
VP-Customer Relations and Sales
Westinghouse Electric Company
6000 Fairview Rd., 12th Floor
Charlotte, NC 28210

Dr. John M. Barry
Mecklenburg County
Department of Environmental
Protection
700 N. Tryon St.
Charlotte, NC 28202

County Manager of York County
York County Courthouse
York, SC 29745

Mr. Richard M. Fry, Director
Division of Radiation Protection
North Carolina Department of
Environment, Health, and
Natural Resources
3825 Barrett Dr.
Raleigh, NC 27609-7721

Ms. Karen E. Long
Assistant Attorney General
North Carolina Department of
Justice
P. O. Box 629
Raleigh, NC 27602

Mr. C. Jeffrey Thomas
Manager - Nuclear Regulatory
Licensing
Duke Energy Corporation
526 South Church St.
Charlotte, NC 28201-1006

NCEM REP Program Manager
4713 Mail Service Center
Raleigh, NC 27699-4713

Mr. T. Richard Puryear
Owners Group (NCEMC)
Duke Energy Corporation
4800 Concord Rd.
York, SC 29745

Mr. Gary Gilbert
Regulatory Compliance Manager
Duke Energy Corporation
4800 Concord Rd.
York, SC 29745

North Carolina Municipal Power
Agency Number 1
1427 Meadowwood Blvd.
P. O. Box 29513
Raleigh, NC 27626-0513

Piedmont Municipal Power Agency
121 Village Dr.
Greer, SC 29651

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

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

Senior Resident Inspector
4830 Concord Rd.
York, SC 29745

Lou Zeller
Blue Ridge Environmental
Defense League
P.O. Box 88
Glendale Springs, NC 28629

Paul Gunter
Nuclear Information &
Resource Service
1424 16th Street NW, Suite 404
Washington, DC 20036

Don Moniak
Blue Ridge Environmental Defense League
Aiken Office
P.O. Box 3487
Aiken, SC 29802-3487

Mr. Kevin Cox
The Huntersville Star
P. O. Box 2542
Huntersville, NC 28070

Mr. Robert L. Gill, Jr.
Duke Energy Corporation
Mail Stop EC-12R
P. O. Box 1006
Charlotte, SC 28201-1006

Mr. Henry J. Porter, Assistant Director
Division of Waste Management
Bureau of Land & Waste Management
S.C. Dept of Health and Environ. Control
2600 Bull St.
Columbia, SC 29201-1708

Mr. L. A. Keller
Duke Energy Corporation
526 South Church St.
Charlotte, NC 28201-1006

Mr. Gregory D. Robison
Duke Energy Corporation
Mail Stop EC-12R
526 S. Church St.
Charlotte, NC 28201-1006

Mary Olson
Nuclear Information & Resource Service
Southeast Office
P.O. Box 7586
Asheville, NC 28802

Mr. Alan P. Nelson
Nuclear Energy Institute
1776 I Street, N.W., Suite 400
Washington, DC 20006-3708

Enclosure

The high-voltage portion of the neutron monitoring systems would appear to be a worst-case subset of the low-signal-level instrumentation circuit category. These circuits operate with low-level logarithmic signals that are sensitive to relatively small changes in signal strength, and they operate at a high voltage which could create larger leakage currents if that voltage is impressed across associated cables and connections. Radiation monitoring cables have also been found to be particularly sensitive to thermal effects. NRC Information Notice 97-45, Supplement 1, describes this phenomenon. The neutron monitoring circuits and radiation monitors, therefore, might be candidates for the calibration approach but not necessarily for the visual inspection approach.

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

In its response to open item 3.6.1-1, dated October 2, 2002, the applicant reiterated its view that visual inspections have proven to be effective and useful because visual inspections have revealed potential problems. The applicant asserted that problems that have not developed to the point of component failure can be identified through visual inspection. The applicant also stated that mechanical properties must change to the point of embrittlement and cracking before significant electrical changes are observed. Embrittlement and cracking are signs of extensive aging that are easily detectable by visual inspection. Signs of less extensive aging, such as discoloration, also are easily detectable by visual inspection. Visual inspection can detect aging degradation early in the aging process before significant aging degradation or failure has occurred.

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

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

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

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

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

License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits. The License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits is generically applicable to both McGuire and Catawba, except as otherwise noted. The staff's evaluation of the applicant's AMP focused on the program elements rather than details of specific plant procedures. To determine whether the applicant's aging management program is adequate to manage the effects of aging so that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective action, (8) confirmation process, (9) administrative controls, and (10) operating experience. The staff's evaluation of the elements for corrective action, confirmation process, and administrative controls is documented in Section 3.0.4 of this SER. The staff's evaluation of the remaining elements follows.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3.6.1.3 Conclusions

Based on the review of the LRA and the applicant's responses to the staff's RAI and SER open and confirmatory items, the staff concludes that the implementation of Non-EQ Insulated Cables and Connections Aging Management Program and License Renewal Program for High-range Radiation and Neutron Flux Instrumentation Circuits will provide reasonable assurance that the aging effects associated with heat, radiation, and moisture for insulated cables and connections will be managed. This program will provide reasonable assurance that the intended functions of electrical cables and connections will be maintained consistent with the current licensing basis through the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2 Aging Effects Caused by Moisture and Voltage Stress for Inaccessible Medium-Voltage Cables

3.6.2.1 Technical Information in the Application

In Section 3.6.2 of the LRA, the applicant described the aging effects caused by moisture and voltage stress for inaccessible medium-voltage cables.

3.6.2.1.1 Aging Effects

The applicant states that it has identified aging effects caused by moisture and voltage stress as potential aging effects for inaccessible (for example, in conduit or direct buried) non-EQ (not subject to 10 CFR 50.49 Environmental Qualification requirements) medium-voltage cables that are exposed to significant moisture while energized. Significant moisture is defined by the applicant as exposure to long-term (over a long period such as a few years), continuous (going on or extending without interruption or break) standing water. Periodic exposures to moisture that last for shorter periods are not significant (for example, rain and drain exposure that is normal to yard cable trenches). Medium-voltage cables routed in conduit at Catawba are not a concern due to the design criterion documented in UFSAR Section 8.3.1.4.5.1, “Cable Installation,” that conduit runs are sloped for drainage. In addition to being exposed to long-term continuous standing water and voltage stress, inaccessible non-EQ medium-voltage cables must normally be energized more than 25 percent of the time in order to be susceptible to electrical degradation. The applicant also states that the two criteria identified above are conservative and are used only as threshold values for an inaccessible non-EQ medium-voltage cable to be identified as susceptible to aging effects caused by moisture and voltage stress. A qualifier to these two criteria is that if an inaccessible non-EQ medium-voltage cable is designed for or specified for the conditions described in these two criteria, then the cable is not considered susceptible to aging effects caused by moisture and voltage stress.

3.6.2.1.2 Aging Management Programs

Table 3.6-5 of the LRA credits the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program for managing the identified aging effects for inaccessible non-EQ medium-voltage cables. A description of this AMP is provided in Appendix B of the LRA. The applicant concludes that this program will provide reasonable assurance that the intended functions of inaccessible medium-voltage cables will be maintained consistent with the CLB through the period of extended operation.

3.6.2.2 Staff Evaluation

This section of the SER provides the staff’s evaluation of the applicant’s aging management review for aging effects and the applicant’s aging management program credited for the aging management of inaccessible non-EQ medium voltage cables at McGuire and Catawba. The staff's evaluation includes a review of the aging effects considered. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on cables will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2.1 Aging Effects

Most electrical cables in nuclear power plants are located in dry environments. However, some cables may be exposed to condensation and wetting in inaccessible locations, such as conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations. When an energized cable not specifically designed for submergence is exposed to these conditions, water treeing or a decrease in the dielectric strength of the conductor insulation can occur. This can potentially lead to electrical failure. The growth and propagation of water trees is somewhat unpredictable and occurrences have been noted for cable operated below 15 kV. Water treeing is a long-term degradation and failure phenomenon that is documented only for medium-voltage electrical cables.

The applicant identified formation of water trees and localized damage as applicable aging effects for the inaccessible non-EQ medium-voltage cables caused by moisture and voltage stress. The staff concurs with the aging effects identified above by the applicant for inaccessible medium-voltage cables.

3.6.2.2.2 Aging Management Program

The staff's evaluation of the applicant's AMP focused on the program element rather than details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective action, (8) confirmation process, (9) administrative controls, and (10) operating experience. The staff's evaluation of the elements for corrective action, confirmation process, and administrative controls is documented in Section 3.0.4 of this SER. The staff's evaluation of the remaining elements follows.

[Program Scope] In the previous AMP, the scope of the Inaccessible Non-EQ Medium-Voltage Cable Aging Management Program includes inaccessible (for example, in conduit or direct buried) non-EQ (not subject to 10 CFR 50.49 Environmental Qualification requirement) medium-voltage cables that are exposed to significant moisture with significant voltage. Significant moisture is defined by the applicant as exposure to long-term (over a long period such as a few years), continuous (going on or extending without interruption or break) standing water. Periodic exposures to moisture that last for short periods are not significant (i.e., rain and drain exposure that is normal to yard cable trenches). Significant voltage exposure is defined as being subjected to system voltage for more than 25 percent of the time. The moisture and voltage exposures described as significant in these conditions are not significant for medium-voltage cable that are designed for these conditions (e.g., continuous wetting and continuous energization are not significant for submarine cables).

It was not clear to the staff that exposure of inaccessible medium-voltage cables to moisture for a period of “a few years” is not significant. By letter dated January 17, 2002, the staff requested, in RAI B.3.19-2, the applicant to explain why exposure to moisture over more than a few days, and up to a few years, is not significant. In response to the staff request, in a letter dated April 15, 2002, the applicant states that based on a review of industry literature on the topic of medium-voltage cables being exposed to moisture for long periods, no quantifiable data were found in the documents. However, the data and discussion in this industry literature (for example, EPRI TR-103834-P1-2, “Effects of Moisture on the Life of Power Plant Cables,” and SAND 96-0344, “Aging Management Guideline for Commercial Nuclear Power Plants — Electrical Cables and Termination”) provide the general conclusion that there should not be a problem with a medium-voltage cable even if it is exposed to moisture for several years.

The staff noted that the applicant’s reference (SAND 96-0344, Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cables and Termination) states the following in Section 4.1.2.4:

> Note, however, that even minor and/or intermittent surface condensation, in conjunction with voltage stress and contaminants, may create an environment where surface tracking may occur. Furthermore, some evidence exists to indicate that the rate of diffusion of water through a polymer is relatively independent of form [4.38]. Therefore, the water diffusion rate for a “dry” material in a 100 percent RH atmosphere may not be different than that for the same material completely submerged in water.

It was not clear to the staff that inaccessible cables exposed to moisture for a period of “a few years” was not significant. The applicant’s response did not resolve the issue of cables exposed to wet conditions for which they are not designed.

By letter dated July 9, 2002, the applicant provided the following statement to resolve this issue:

> Duke agrees with the staff on this point. To resolve this item, Duke has eliminated the qualifier “significant” when describing moisture with regards to the program. The program now takes a bounding approach by stating, “Cables that are direct buried, run in horizontally-run buried conduit or run in outside cable trenches are assumed to be exposed to standing water.” In-scope medium-voltage cables that are exposed to standing water and also exposed to significant voltage will be tested.

As a result of eliminating the qualifier “significant” when describing moisture in the programs, the applicant proposes to revise the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program attributes to the following:

> Scope – The scope of the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* includes inaccessible non-EQ medium-voltage cables within the scope of 10 CFR 54.4 that are exposed to significant voltage and to standing water (for any period of time).
>
> Key Definitions and Assumptions: Inaccessible cables are those that are not able to be approached and viewed easily, such as in conduits or cable trenches; all others are accessible. A cable that has a portion of the cable routing that is inaccessible is an inaccessible cable. Non-EQ means not subject to 10 CFR 50.49 Environmental Qualification requirements. Medium-voltage cables are those applied at a system voltage greater than 2kV. Significant voltage is defined as exposure to system voltage for more than twenty-five percent of the time. Cables that are direct buried, run in horizontally-run buried conduit or run in outside cable trenches are assumed to be exposed to standing water.

Preventive Actions – Preventive actions are not included in the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program*.

Parameters Monitored or Inspected – Medium-voltage cables within the scope of the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* are tested to provide an indication of the condition of the conductor insulation. The specific type of test performed will be determined before each test. Each test performed for a cable may be a different type of test.

Detection of Aging Effects – Medium-voltage cables within the scope of the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* are tested at least once every 10 years. This is an adequate frequency to preclude failures of the conductor insulation.

Monitoring and Trending – Trending actions are not included in the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program*.

For McGuire, the first test per the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* will be completed following issuance of renewed operating licenses for McGuire Nuclear Station and by June 12, 2021 (the end of the initial license of McGuire 1). For Catawba, the first test per the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* will be completed following issuance of renewed operating licenses for Catawba Nuclear Station and by December 6, 2024 (the end of the initial license of Catawba 1).

Acceptance Criteria – The acceptance criteria for each test is defined by the specific type of test performed and the specific cable tested.

Corrective Actions & Confirmation Process – Further investigation through the corrective action program is performed when the acceptance criteria are not met. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other medium-voltage cables within the scope of this program. Confirmatory actions, as needed, are implemented as part of the corrective action process.

Administrative Controls – The *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* is controlled by plant procedures.

Operating Experience – Operating experience is not relevant for this new program.

The staff finds that the scope of the revised program is acceptable since the applicant has agreed to eliminate the qualifier “significant” when describing cables that are exposed to moisture and this issue is resolved. The staff evaluated the applicant’s revised attributes for Parameters Monitored or Inspected, Detection of Aging Effects, Acceptance Criteria, and Corrective Action and Confirmation Process, and documented its evaluation in the applicable paragraphs that follow in this SER section. The other attributes were not affected by the revisions to this program. Therefore, the staff evaluated these attributes as they were described in the LRA. The staff notes that the FSAR supplement should be revised to reflect the change in the Inaccessible Non-EQ Medium-Voltage Cable Aging Management Program, as discussed in its evaluation of the FSAR supplement below.

[Preventive Actions] In the previous AMP, the applicant stated that no preventive actions are required as part of the Inaccessible Non-EQ Medium-Voltage Cable Aging Management Program. Periodic actions may be taken to prevent inaccessible non-EQ medium-voltage cables from being exposed to significant moisture such as inspecting for water collection in cable manholes and conduit and draining water as needed. Testing of a cable per this program is not required when such preventive actions are taken since the significant moisture criteria defined under Program Scope would not be met.

Periodic actions should be taken to prevent cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes and conduit and draining water as needed. Medium-voltage cables for which such actions are taken are not required to be tested. By letter dated January 17, 2002, the staff requested the applicant in RAI B.3.19-1 to explain why no preventive actions were specified as part of its AMP. In its response dated April 15, 2002, the applicant stated that the McGuire and Catawba proposed program for medium-voltage cable is written specifically for "inaccessible medium-voltage cables, i.e., cables that cannot be accessed." In a long cable run in a conduit or concrete trench or direct buried, most of the length is inaccessible, which means that most of the cable length is not accessible for inspection to determine if it is exposed to significant moisture. If any portion of a medium-voltage cable along its entire run is inaccessible and could be subject to significant moisture exposure, that cable would be identified as inaccessible and possibly subject to testing per the McGuire and Catawba program. The McGuire and Catawba program for medium-voltage cable was not written for accessible medium-voltage cables. During the review performed to respond to the staff's RAI, it was realized that there may be cases where it is practical to perform periodic actions to limit exposure of medium-voltage cables to moisture and, thus, mitigate any aging effects. These actions, such as inspecting cable manholes for water collection, would mainly cover the accessible portions of these cables that may provide symptomatic evidence of the conditions to which other portions of the cable are exposed. Based on the review performed to respond to the staff's RAI, the applicant would change the program descriptions contained in McGuire FSAR supplement 18.2.15 and Catawba FSAR supplement 18.2.14 by replacing existing text with the following text in the Scope, Preventive Actions and Monitoring and Trending program attributes:

> [Scope] The scope of the Inaccessible Non-EQ Medium-Voltage Cable Aging Management Program includes inaccessible non-EQ medium-voltage cables within the scope of 10 CFR 54.4 that are exposed to significant voltage simultaneously with significant moisture.
>
> Key Definition and Assumptions: Inaccessible cables are those that are not able to be approached and viewed easily, such as in conduits or cable trenches; all other are accessible. Non-EQ means not subject to 10 CFR 50.49 Environmental Qualification requirements. Medium-voltage cables are those applied at a system voltage greater than 2kV and less than 15kV. Significant voltage is defined as exposure to system voltage for more than 25 percent of the time. Significant moisture is defined as exposure to long-term (over a long period such as few years), continuous (going on or extending without interruption or break) standing water. Periodic exposures to moisture for shorter periods are not significant (for example, rain and drain exposure that is normal to yard cable trenches). Significant moisture is assumed to be present unless engineering data indicates otherwise. The moisture and voltage exposures described as significant in these definitions are not significant for medium-voltage cables that are designed for these conditions (for example, continuous wetting and continuous energization is not significant for submarine cables).
>
> [Preventive Actions] Periodic actions are taken where practical, as determined by the accountable engineer, to mitigate any aging effects by limiting the exposure of inaccessible non-EQ medium-voltage cables to moisture, such as inspecting for water collection in cable manholes and conduits and draining water as needed.
>
> [Monitoring and Trending] Inaccessible non-EQ medium-voltage cables exposed to significant moisture and significant voltage are tested at least once every 10 years per the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program to provide an indication of the condition of the conductor insulation and the ability of the cable to perform its intended function. The specific type of test performed will be determined before each test. Each test performed for a cable may be a different type of test. Testing of a cable per this program is not required if periodic actions as described under preventive actions are taken and those actions prevent, with reasonable assurance, the cable from being exposed to significant moisture (since the significant moisture criteria defined under Scope would not be met).

The staff found the applicant’s response acceptable because the applicant would take preventive actions, when practical, to mitigate any aging effects by limiting the exposure of inaccessible cables to moisture. Testing of a cable per this program is not required if periodic actions are taken and those actions prevent the cable from being exposed to significant moisture.

In the July 9, 2002, letter, the applicant revised the preventive action attribute to the following: “Preventive actions are not included in the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program.”

The staff finds this revision acceptable because, as long as the applicant tests the medium-voltage cables that are exposed to significant voltage and standing water for any period of time every 10 years, no preventive actions are necessary.

[Parameters Monitored or Inspected] Medium-voltage cables within the scope of the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program are tested to provide an indication of the condition of the conductor insulation. The specific type of test performed will be determined before each test. Each test performed for a cable may be a different type of test.

The staff was unable to determine if the test to be performed will be an appropriate test that has been proven to accurately assess the cable condition with regard to water treeing. In a letter dated October 19, 2002, the staff requested the applicant to modify this attribute to indicate that the test to be performed will be a proven test for detecting deterioration of insulation systems due to wetting. The staff requested this modification so that it can make a reasonable assurance finding that the test will be capable of detecting insulation degradation and that the effects of aging on inaccessible non-EQ medium-voltage cables will be adequately managed, so that the intended function will be maintained in accordance with the requirement of 10 CFR 54.21(a)(3).

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

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

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

[Detection of Aging Effects] Medium-voltage cables within the scope of the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program are tested at least once every 10 years. This is an adequate frequency to preclude failures of the conductor insulation. The staff believes, based on current knowledge, that aging degradation of this cabling would be due to slow-acting mechanisms. Therefore, the applicant’s test schedule is acceptable.

[Monitoring and Trending] In the previous AMP, the applicant stated that inaccessible non-EQ medium-voltage cables exposed to significant moisture and significant voltage are tested at least once every 10 years per the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program to provide an indication of the condition of the conductor insulation and the ability of the cable to perform its intended function. The specific type of test performed will be determined before each test. Each test performed for a cable may be a different type of test. Testing of a cable per this program is not required if periodic actions are taken and if those actions prevent, with reasonable assurance, the cable from being exposed to significant moisture (since the significant moisture criteria defined under Program Scope would not be met). Since the alternate visual inspection program was proposed to testing, the staff determined that the applicant's monitoring and trending attribute did not provide adequate information about the proposed alternative inspection program to testing in that it did not specify (1) the frequency of inspection, (2) how inspection results will be monitored and trended, (3) if or when operability evaluations for degraded conditions (presence of moisture) would be performed, (4) if or when testing would be performed if moisture is identified, and (5) what corrective actions would be taken in the event that cables exposed to moisture are identified. By letter dated June 26, 2002, the staff identified potential open item B.3.19.2-1 as mentioned above and requested the applicant to provide additional information in response to this potential open item.

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

> The alternative visual inspection program was proposed in the McGuire and Catawba LRA in an attempt to provide a distinction between cables that are exposed to moisture (rain and drain) and those that are exposed to "significant" moisture so that the cables exposed only to "rain and drain" would not require testing. Trying to quantify this distinction has proven difficult and has raised staff concerns that this distinction, improperly applied, could inadvertently exclude some applicable cables from the program. Duke acknowledges the staff's concern in this area along with the recognition that some cable installations make it impossible (by currently known means) to verify with reasonable assurance that all portions of some cable runs are not continuously exposed to moisture. Considering these factors, Duke has now eliminated this distinction regarding moisture exposure by taking a bounding approach. The aging management program will include any significant voltage exposed in-scope medium-voltage cables that are exposed to standing water (for any period of time). With the moisture distinction eliminated and all such cables included without further qualification, the need for the proposed alternative inspection program is eliminated.

Since the applicant eliminated the inspection alternative to the 10-year test described in the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program, this issue is resolved.

The applicant also revised the Monitoring and Trending attribute, stating that trending actions are not included in the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program. For McGuire, the first test per the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program will be completed following issuance of renewed operating licenses for McGuire and by June 12, 2021 (the end of the initial license of McGuire 1). For Catawba, the first test per the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program will be completed following issuance of renewed operating licenses for Catawba and by December 6, 2024 (the end of the initial license of Catawba 1). The staff finds that the absence of trending for testing is acceptable since the test is performed every 10 years, and the staff does not see a need for such activities. The staff also finds the testing schedule acceptable to preclude failures of the conductor insulation since aging degradation is a slow process.

[Acceptance Criteria] The acceptance criteria for each test are defined by the specific type of test performed and the specific cable tested. The staff finds the above acceptance criteria acceptable on the basis that they will follow current industry standards which, when implemented, will ensure that the license renewal intended functions of the cables will be maintained consistent with the current licensing basis.

[Operating Experience] Operating experience is not relevant for this new program. Industry experience supports both the need for the program and the attributes of the applicant's program. Thus, the staff finds that operating experience is satisfactorily incorporated into the development of this new program.

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

3.6.2.3 Conclusions

On the basis of the staff's evaluation described above, the staff finds that there is reasonable assurance that the effects of aging of inaccessible non-EQ medium-voltage cables will be adequately managed, so that the intended functions will be maintained consistent with the applicant's CLB for the period of extended operation in accordance with the requirement of 10 CFR 54.21(a)(3).

3.6.3 Aging Effects Caused by Boric Acid Ingress into Connector Pins

3.6.3.1 Technical Information in the Application

In Section 3.6.3 of the LRA, the applicant described the aging effects caused by boric acid ingress into connector pins. The applicant states that potential acid ingress into connector pins was identified as causing aging effects that need to be managed.

3.6.3.1.1 Aging Effects

Table 3.6-1 on page 3.6-1 of the LRA identified corrosion of connector pins as an aging effect caused by exposure to borated water.

3.6.3.1.2 Aging Management Program

The applicant states that it will take credit for an existing program, the Fluid Leak Management Program (which includes boric acid leakage surveillance), for managing aging effects caused by boric acid ingress into non-EQ connector pins at McGuire and Catawba. This AMP is described by the applicant in Section B.3.15 of LRA Appendix B.

3.6.3.2 Staff Evaluation

This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management program credited for the aging management of connector pins at McGuire and Catawba Nuclear Stations. The staff's evaluation includes a review of the aging effects considered. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on connector pins will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.3.2.1 Aging Effects

Aging effects caused by oxidation or corrosion of connector pins because of potential boric acid ingress into connector pins could cause connector failure and interfere with the operation of these circuits. The applicant identified corrosion as an applicable aging effect for the connector pins. The staff concurs with the aging effects identified above by the applicant.

3.6.3.2.2 Aging Management Programs

The staff evaluated the information on aging effects caused by boric acid ingress into connector pins as presented in Section 3.6.3 of the LRA to determine if there is a reasonable assurance that the applicant has demonstrated that the aging effects for low-voltage connectors will be adequately managed, consistent with the applicant's CLB for the period of extended operation.

The applicant credits the Fluid Leak Management Program to manage the aging effects caused by boric acid ingress into non-EQ low-voltage connector pins. Since the Fluid Leak Management Program is credited for managing the aging of several structures and components in different systems, it is considered a common AMP and the staff's evaluation of it is documented in Section 3.0 of the SER. The AMP's effectiveness has been evaluated for electrical components as well. The staff finds that this program is adequate to manage the effect of corrosion of the electrical components.

3.6.3.3 Conclusions

Based on the review of the LRA, the staff concludes that the implementation of the Fluid Leak Management Program will provide a reasonable assurance that the aging effects of oxidation or corrosion of connector pins will be managed. This program will provide reasonable assurance that the intended functions of low-voltage connectors will be maintained consistent with the current licensing basis through the period of extended operation, as required by 10 CFR 54.21(a)(3).

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

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

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

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

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

3.6.4.1.1 Aging Effects

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

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

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

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

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

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

3.6.4.1.2 Aging Management Programs

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

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

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

3.6.4.2.1 Aging Effects

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

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

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

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

3.6.4.2.2 Aging Management Programs

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

3.6.4.3 Conclusions

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

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

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

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

3.6.4.4.1 Aging Effects

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

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

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

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

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

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

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

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

3.6.4.4.2 Aging Management Programs

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

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

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

3.6.4.5.1 Aging Effects

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

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

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

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

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

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

3.6.4.5.2 Aging Management Programs

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

3.6.4.6 Conclusions

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

THIS PAGE IS INTENTIONALLY LEFT BLANK