February 11, 2002

LICENSEE : Duke Energy Corporation

FACILITIES: McGuire, Units 1 and 2, and Catawba, Units 1 and 2

SUBJECT: TELECOMMUNICATION WITH DUKE ENERGY CORPORATION TO DISCUSS INFORMATION IN THEIR LICENSE RENEWAL APPLICATION ON REACTOR COOLANT SYSTEM COMPONENTS IN SECTIONS 3.1, B.3.1, B.3.26, B.3.27, B.3.31 AND 4.2.1

On January 9, 2002, after the staff reviewed information pertaining to the reactor vessel and other reactor coolant system components provided in Sections 3.1, B.3.1, B.3.26, B.3.27, B.3.31, 4.2.1 of the license renewal application (LRA), a conference call was conducted between the NRC and Duke Energy Corporation to clarify information presented in the application pertaining to the management of aging for those components. Participants of the conference call are provided in an attachment.

The questions asked by the staff, as well as the responses provided by the applicant, are as follows:

<u>3.1.1 Reactor Coolant System - Class 1 Piping, Valves, and Pump Casings</u>

3.1.1-1 In accordance with Section 3.1.1 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the reactor coolant system (RCS) piping and associated components to provide reasonable assurance that the aging effects which require management for a specific material-environment combination are the only aging effects of concern for McGuire and Catawba. This also included the plant-specific operating experience at both plants. Discuss the process used to evaluate the industry issues, including the plant-specific and NRC generic issues, associated with the RCS Class 1 piping and associated components, and explain the methodology for determining the resulting aging effects that require management.

The applicant and staff agreed that this information was not needed to make a reasonable assurance finding on the aging management of RCS piping, valves and pump casings.

3.1.1-2 In WCAP-14575-A, loss of material resulting from wear of the reactor coolant pumps (RCPs) and Class 1 valve bolted closures is identified as an aging effect requiring management. The report credits the ASME Code Section XI inservice inspection (ISI) requirements as the applicable AMP for managing this effect. In Section 3.3.1 of the staff's Final Safety Evaluation Report for WCAP-14575-A, the staff concluded that this was acceptable. The applicant has not identified loss of material as an applicable effect for RCS valve bolting materials. Clarify whether loss of material (resulting from wear) is an applicable effect for the RCS valve bolting materials exposed to reactor building environments. If loss of material is an applicable effect for the RCS valve bolting materials, identify which AMPs will be used to manage the effect, and justify why you consider the AMPs to be sufficient to manage loss of material in the valve bolting materials during the extended periods of operation.

The applicant directed the staff to aging management review (AMR) results table 3.1-1, page 3.1-5 of the LRA. The table indicated that the bolts are stainless steel and, therefore, not susceptible to loss of material. The staff reviewed the Generic Aging Lessons Learned (GALL) Report and determined that loss of material was not listed as an applicable aging effect for stainless steel bolts. Therefore, the staff is satisfied with the response provided by the applicant and has no additional questions on this issue.

3.1.1-3 WCAP-14575-A identifies that reactor coolant pump seals are within the scope of license renewal. The report states, however, that the pump seals may be excluded from an AMR if an applicant submits a description of its performance and condition monitoring activities for RCP seals, to ensure the integrity of the seals during the period of extended operation. In order to justify that an AMR for the RCP seals is not necessary, provide a description of the performance and condition monitoring activities, if any, associated with RCP seals and the basis for concluding that these activities will provide reasonable assurance that the RCP seals will meet their intended function through the period of extended operation.

The applicant referred the staff to page 2.3-4 of the LRA, which states that the RCP seals are excluded from an aging management review (AMR) because they are periodically replaced. The staff agrees that RCP seals are not long-lived components and, as such, are not subject to an AMR.

3.1.1-4 Per LRA Table 3.1-1, the loss of material and cracking in orifices are managed by the chemistry control program. Since these restricting orifices are relied upon to separate Class 1 portions from Class 2 portions of the RCS piping in lieu of redundant valves, their continued functionality is extremely important to maintaining the CLB. It is not evident to the staff how the effectiveness of the chemistry control program to manage loss of material and cracking is verified. No supplemental ISI or performance testing is identified. Clarify how the aging effects associated with orifices are adequately managed by the chemistry control program alone, and provide a description of supplemental activities which verify that the chemistry control program is effective.

The applicant indicated that this question is appropriate for a request for additional information (RAI). The applicant will submit information to enable the staff to complete its review of this issue in its formal response to the RAI.

<u>3.1.2 Reactor Coolant System - Pressurizer</u>

3.1.2-1 LRA Section 3.1 does not assess whether the potential exists for existing cracks in the pressurizer cladding to grow (as a result of thermal-fatigue induced crack growth) through the cladding and into the ferritic portions of the pressurizer subcomponents that the cladding is joined to. Discuss whether thermal fatigue-induced crack initiation and growth is an issue for the ferritic pressurizer subcomponents that are protected with austenitic stainless steel cladding, and whether propagation of the cracks through the cladding into the ferritic base material or weld material beneath the clad is an applicable effect that requires management. If propagation of the cracks through the cladding into the ferritic base material or weld material beneath the clad is an applicable effect that requires management, state which AMPs will be used to manage this effect, and justify why you consider the AMPs to be sufficient to manage this effect during the extended periods of operation.

The applicant indicated that this question is appropriate for an RAI. The applicant will submit information to enable the staff to complete its review of this issue in its formal response to the RAI.

3.1.2-2 The staff is concerned that intergranular stress corrosion cracking (IGSCC) in the heat-affected zones of 304 stainless steel supports that are welded to the pressurizer cladding could grow as a result of thermal fatigue into the adjacent pressure boundary during the license renewal term. The staff considers that these welds will not require aging management in the period of extended operation if the applicant can provide reasonable justification that sensitization has not occurred in these welds during the fabrication of these components. Provide a discussion of how the implementation of plant-specific procedures and quality assurance requirements, if any, for the welding and testing of these austenitic stainless steel components provides reasonable assurance that sensitization has not occurred in these welds and associated heat-affected zones.

The applicant indicated that this question is appropriate for an RAI. The applicant will submit information to enable the staff to complete its review of this issue in its formal response to the RAI.

3.1.2-3 LRA Table 3.1-1 identifies loss of preload as an aging effect for the manway cover bolts/studs. Table 3.1-1 also indicates that the aging effects associated with the bolts/studs will be managed using the inservice inspection plan and the fluid leak management program. From the description provided in LRA Appendix B for these two AMPs, it is not clear how loss of preload will be managed for the period of extended operation. Clarify how the inservice inspection plan and the fluid leak management program are sufficient to manage loss of preload of the manway cover bolts/studs.

The applicant indicated that this question is appropriate for an RAI. The applicant will submit information to enable the staff to complete its review of this issue in its formal response to the RAI.

3.1.2-4 Loss of material due to boric acid corrosion is an aging effect requiring management of the external surfaces of the pressurizers. The fluid leak management program is credited with managing boric acid wastage. Typically, NRC GL 88-05 and Section XI requirements for conducting system leak tests and VT-2 type visual examinations of the pressurized pressure boundary are used to manage boric acid corrosion of the external surfaces of the pressurizer. The applicant has not identified that required ISI inspections will be used to manage boric acid corrosion of the external surfaces of the pressurizer. Confirm that during the extend terms of operation you will continue to perform all applicable ISI examinations of the external pressurizer surfaces that are required by Table IWB-2500-1 to Section XI of the ASME Code.

The applicant indicated that ISI will be performed as required during the period of extended operation, but that the Fluid Leak Management Program, and not ISI, is credited for aging management during that period. The staff is satisfied with this response and has no additional questions on this issue.

3.1.3 Reactor Coolant System - Reactor Vessel and Control Rod Drive Mechanism Pressure Boundary

3.1.3-1 Reactor vessel underclad cracking may be an issue for cladding joined to forgings fabricated from SA 508, Class 2 low-alloy steels if the forgings were fabricated to a coarse grain practice and clad by high-heat-input submerged arc processes. Clarify whether any portions of the McGuire and Catawba reactor vessels are fabricated from SA 508, Class 2 low-alloy steels and whether these fabrication practices were used to fabricate the forgings. If any of the McGuire and Catawba reactor vessel materials (including reactor vessel flanges and nozzle materials) are made from SA 508, Class 2 low-alloy steel forgings that have been fabricated to a coarse grain size and clad by high-heat input submerged arc processes, provide a time limited aging effect analysis to manage underside cracking in these components.

The applicant indicated that underclad cracking was not identified in the LRA as a time-limited aging analysis (TLAA) because the UFSARs for both plants describe Duke construction-vintage programs for controlling stainless steel cladding of low-alloy components that are consistent Regulatory Guides 1.43 and 1.44. As such, the applicant indicted that cracking of the stainless steel clad is not an applicable aging effect. The staff will consider the information provided and will review the Catawba UFSAR (Sections 1.7, 5.3.1.4, 5.2.3.4 and 5.2.3.2.2) and the McGuire UFSAR (Sections 1.7, 5.2.3, 5.2.5 and Table1-4) to determine if sufficient information is provided to enable the staff to complete its review of this item.

3.1.3-2 The fluid leak management program was developed in response to Generic Letter 88-05 to manage loss of material in carbon and low-alloy steels exposed to leaking borated water. Table 3.1-1 of the application states that the aging of the reactor vessel closure head dome, flange, and ring and vessel flange is managed by the chemistry control and the ISI programs. Clarify why the fluid leak management program is not identified as an applicable AMP for these components.

The applicant referred the staff to Table 3.1-1, page 3.1-5 of the LRA, which indicates that the fluid leak management program is credited for managing the aging of the exterior surfaces of pressure boundary components. The staff is satisfied with the information provided in the LRA and has no additional questions on this issue.

3.1.3-3 The staff notes that cracking of the core support lugs is an applicable aging effect that needs to be addressed, since the staff does not consider VT-3 visual examination of these RV components under examination category B-N-2 to be adequate. The industry is currently in the process of developing new recommendations (in addition to existing reliance on chemistry control and existing ASME Section XI inspections) for inspection of core support lugs. The staff requests that the applicant describe how it intends to manage this aging effect for the period of extended operation.

The applicant directed the staff to Table 3.1-1, page 3.1-14, which indicates that the Alloy 600 Aging Management Review, the Chemistry Control Program, and the Inservice Inspection Plan are credited for aging management of the core support pads (different nomenclature). The staff is satisfied with the information provided in the LRA and has no additional questions on this issue.

3.1.3-4 (a) In accordance with LRA Table 3.1-1, aging effects of cracking and loss of material associated with the thimble seal table are managed by the chemistry control program alone. Since mechanical seals between the retractable thimbles and the conduits are provided at the seal table, its continued functionality is extremely important for maintaining the CLB. The staff requests clarification on how the effectiveness of the chemistry control program to manage loss of material and cracking is verified, since no supplemental ISI or performance testing to quantify these effects is identified.

(b) In Table 3.1-1 of the application, it is stated that loss of pre-load for the RV closure studs is managed by the ISI plan and the RCS operational leakage monitoring program. During service, the amount of preload put on the studs may drop unacceptably without resulting in a noticeable leak. Clarify how these AMPs are sufficient to manage unacceptable loss of pre-load in RV closure studs during the period of extended operation.

The applicant indicated that part (a) of this question is appropriate for an RAI. The applicant will submit information to enable the staff to complete its review of this issue in its formal response to the RAI. In response to part (b) of this question, the applicant indicated that loss of preload for reactor vessel closure studs is not a reasonable aging effect, since the bolts are detensioned and removed to lift the reactor vessel head every 16 to 18 months for refueling. After refueling activities are completed, the head is set and the vessel stud bolts are reinstalled and tensioned. Since loss of preload does not occur within the span of one cycle, it does not constitute an aging effect. The staff is satisfied with this response and has no additional questions on this issue.

<u>3.1.4 Reactor Coolant System - Reactor Vessel internals</u>

3.1.4-1 In LRA Table 3.1-1, the applicant does not list the rod control cluster assembly guide tube support pins as a separate entry. The staff assumes that they are included with the guide tube assembly. Confirm whether the guide tube support pins at McGuire and Catawba are within the scope of license renewal, and whether the AMRs for the guide tube assemblies in Table 3.1-1 of the application (on pages 3.1-16 and 3.1-17 of the LRA) covers the scope of your AMR for the guide tube support pins. If the guide tube support pins are within scope of license renewal and Table 3.1-1 does not provide an AMR for them, provide an AMR for the guide tube support pins that identifies the aging effects that are applicable to the pins and the aging programs that will be capable of managing the effects.

The applicant referred the staff to Table 3.1-1, page 3.1-16, which indicates that 17X17 and 15X15 guide tube assemblies are stainless steel. The applicant further indicated that the pins are addressed in the LRA as part of the assembly. The staff and applicant also recognized that page 3.1-17 indicated that the 17X17 and 15X15 guide tube assemblies also contain cast austenitic stainless steel (CASS). However, the applicant indicated that all guide tube assembly pins are stainless steel. As such, the programs that are credited to manage the aging of stainless steel pins are Chemistry Control Program and Inservice Inspection Plan, as indicated on page 3.1-16 of Table 3.1-1. The staff will consider the information provided but may request additional information to confirm that the pins are stainless steel and included in the guide tube assembly referred to in Table 3.1-1.

3.1.4-2 In LRA Table 3.1-1, the applicant identified that one of the intended functions for the lower support plate (forging) and lower core support columns is to provide neutron shielding to the reactor vessel. These components are exposed to both high temperature and high radiation conditions. The applicant did not identify reduction in fracture toughness due to irradiation as one of the applicable aging effects for these RVI components. Provide the technical basis for not including reduction in fracture toughness as one of the applicable aging effects for the lower support plate (forging) and lower core support columns.

The applicant indicated that Note 6, which represents the function to provide neutron shielding to the reactor vessel and to provide support for vessel material test specimens, does not apply to the lower support plate (forging) and lower core support columns and that the LRA is in error. Nonetheless, the effect of reduction in fracture toughness is not significant because the forging is composed of stainless steel, it is not adjacent to the core, and it is in a relatively low radiation field. The staff will consider this response but may request additional information to confirm that accumulated neutron fluence for these components will be lower than $5x10^{20}$ neutrons/cm^2 (E > 1 MeV) for radiation-induced embrittlement during the extended period of operation such that loss of fracture toughness is not an applicable effect.

3.1.4-3 The McGuire and Catawba UFSARs describe that the main radial support for the lower end of the core barrel is accomplished by “key” and “keyway” joints to the reactor vessel wall. In regard to these joints, an Inconel clevis block is welded to the vessel inner circumference at equally spaced points. Another Inconel insert block is bolted to each of these blocks and has a “keyway” geometry. Opposite each of these is a “key” which is attached to the internals. The staff considers that the clevis insert fasteners are susceptible to loss of preload due to stress relaxation during normal operation. In LRA Table 3.1-1, the applicant has not identified loss of preload as an applicable aging effect for the clevis insert fasteners. Discuss the technical basis for not including loss of preload as an applicable aging effect for the clevis insert fasteners.

The applicant requested that the staff provide a reference to operating experience pertaining to loss of preload of the clevis insert fasteners. The staff may request additional information to complete its review of this item and will include an appropriate reference to establish that loss of preload is an applicable aging effect for clevis insert fasteners.

3.1.4-4 Although void swelling has not been observed to date, the staff is concerned that void swelling may become significant during the period of extended operation. Until industry has developed sufficient data to demonstrate that void swelling is not a significant aging mechanism, the staff believes that void swelling should be considered significant, and applicants for license renewal should describe their aging management plan to address void swelling in the reactor vessel internal (RVI) components. In LRA Table 3.1-1, the applicant has identified change in dimension as an applicable aging effect for some of the RVI components, presumably those exposed to the highest neutron fluence. The staff needs additional information concerning the criteria applied to establish which RVI components are susceptible to change in dimension due to void swelling. Provide the technical basis for determining which RVI components are susceptible to void swelling and which RVI components are not susceptible.

The applicant indicated that void swelling (dimensional changes) was listed in Table 3.1-1, on pages 3.1-18 and 3.1-19, as an applicable aging effect. The staff confirmed that Table 3.1-1 does include reference to dimensional changes but may request additional information to confirm that the reactor vessel internal components identified in the table as being potentially susceptible to this effect are the limiting dimensional change (due to void swelling) locations within the reactor vessel cavity, as evaluated from an accumulated neutron fluence basis for the components.

<u>3.1.5 Reactor Coolant System - Steam Generators</u>

3.1.5-1 Per Table 3.1-1, the loss of material and cracking in the steam flow limiter, the feedwater thermal sleeves, the handhole diaphragm, and the auxiliary feedwater distribution system are managed by the Chemistry Control Program. The staff needs clarification about the effectiveness of the Chemistry Control Program to manage loss of material and cracking. No supplemental ISI or performance testing is identified for these SG components. Clarify how the Chemistry Control Program by itself is sufficient to manage loss of material and cracking in these components.

The applicant indicated that this question is appropriate for an RAI. The applicant will submit information to enable the staff to complete its review of this issue in its formal response to the RAI.

3.1.5-2 In accordance with UFSAR Section 5.4.2.4 for Catawba, the Unit 2 Westinghouse SGs are equipped with a preheater and feedwater flow restrictor with main feedwater delivered just above the tubesheet while the feedwater in the Unit 1 BWI RSGs delivered to the annulus area outside the top of the tube bundle and distributed by a feedring header. It is not clear if the feedwater delivery systems in BWI RSGs at Catawba 1, McGuire 1 and McGuire 2 have flow restrictors.

(a) Clarify if the feedwater flow restrictors are present in all four subject plant SG units.

(b) Table 3.1-1 identifies the Inservice Inspection Plan and the Chemistry Control Program to detect cracking and loss of material in the flow restrictors and steam flow limiters. Describe what kinds of inservice inspections are performed on these components.

The applicant indicated that the replacement steam generators do not use feedwater flow restrictors but, rather, use a feed ring design. The staff and applicant agreed that a request for additional information would provide the applicant with an opportunity to submit information pertaining to the steam generator design in its formal response to the RAI.

3.1.5-3 Based on the Generic Letter (GL) 97-06 licensee's responses to GL 97-06 submitted for Catawba 1, the plant completed its first fuel cycle of operation in November 1997. The tubing was then surveyed using eddy current testing, and the upper-bundle and tubesheet regions visually or by video camera. Similar inspections were also completed on the BWI RSGs at Millstone 2 and Ginna. During SG internal inspections in these three plants after their first service period, it was determined that positioning of the U-bend support components could result in contact between peripheral tubes.

(a) Describe the current conditions of the peripheral tubes in BWI RSGs and how the applicant intends to manage the susceptibility of peripheral tubes coming into contact during operation which may lead to fretting wear from flow-induced vibration at the point of contact.

(b) The applicant indicated in its response to GL 97-06 that it would follow the Westinghouse Owners Group (WOG) and Babcock & Wilcox Owners Group (B&WOG) recommendations as part of its continuing secondary-side inspection program. The owners groups suggested additional inspections to be included in the existing inspection activities for a long-term solution to degradation in SG internals. The applicant has committed to establish a program to monitor SG secondary side components consistent with the requirements of NEI 97-06. Describe the plan for implementing the owners group recommendations for the SG internals inspections.

The applicant responded that, although the program credited for managing the aging of SG tubes is subject to future enhancement as the industry's understanding of degradation mechanisms continues to improve, the question (parts a and b) applies to the current operation of the plants and, as such, pertains to current licensing basis. The staff and applicant agreed that the nature of this question is beyond the scope of license renewal. As such, no additional information is needed for the staff to complete its review of this issue as it relates to the aging management and the requirements of 10 CFR 54.

3.1.5-4 (a) In LRA Table 3.1-1, the applicant has included the steam generator (SG) bolting as one of the component requiring aging management. However, it is not clear whether loss of preload for the manway and handhole cover bolts/studs is covered by this component group. Confirm that the SG bolting identified in Table 3.1-1 includes both the bolts and studs for all steam generator bolted connections within the scope of license renewal.

(b) LRA Table 3.1-1 also identifies loss of material, cracking, and loss of preload as aging effects for the SG bolting, and states that the Inservice Inspection Plan and the Fluid Leak Management Program will be used to manage these effects. It is not clear how these programs are sufficient to manage loss of preload in the bolting. Clarify how these two AMPs are sufficient to manage loss of preload of the SG bolts/studs.

In response to part (a) of this question, the applicant referred the staff to Table 3.1-1, page 3.1-5, which indicates that all steam generator bolting is included in the component group to the extent that it supports a pressure boundary function that caused the bolts to meet the scoping criteria of 10 CFR 54.4. The applicant also noted that bolts and studs are synonymous and clarified that studs are typically referred to in the context of the reactor vessel head. In response to part (b), the applicant indicated that the programs credited for managing the aging of SG bolting are adequate because they will reveal leakage resulting from any degradation of the SG bolting. As such, the programs are used to monitor the effects of aging (rather than manage the effects of aging), in accordance with the Generic Aging Lessons Learned (GALL) report, program XI.M18, Bolting Integrity. The staff is satisfied with this response and has no additional questions on this issue.

3.1.5-5 The Steam Generator Surveillance Program, described in Section B.3.31 of Appendix B of the LRA, covers eddy current and visual examinations of all Duke Alloy 600 and Alloy 690 steam generator tubes, plugs, and sleeves, as well as internal support structures. The intent of the program is to detect loss of material and cracking prior to loss of intended function. The staff notes, however, that in Table 3.1-1 of the LRA, the only steam generator components listed for this AMP are the tubes, tubesheets, and tube plugs. The applicant has not included any SG internal support structures within the scope of the license renewal. Therefore, it appears that a discrepancy exists as to whether the tube support plates and anti-vibration bars are within the scope of license renewal. If the tube support plates and anti-vibration bars are within the scope of license renewal, perform an AMR of these components identifying the aging effects that are applicable to them, and if aging effects are applicable state which programs or activities will be used to manage the effects within the extended periods of operation for the McGuire/Catawba units. If the anti-vibration bars and tube support plates are not within scope, confirm by stating so.

The applicant and staff recognized that this question was raised during the staff's scoping review of LRA section 2.3.1. As such, this issue will be addressed as it pertains the staffs review of that section.

Appendix B, B.3.1, Alloy 600 Aging Management Review

B.3.1-1 Your description of the Alloy 600 Aging Management Review (AMR) provided in Section B.3.1 to Appendices B of the applications does not identify those Alloy 600 82/182, or 52/152 components or locations within the scope of the program. Identify all Alloy 600, 82/182, or 52/152 components or locations within the scope of the Alloy 600 AMR.

The applicant indicated that Table 3.1-1 listed the Alloy 600 components within the scope of license renewal and subject to the Alloy 600 AMR. The staff is satisfied with the information provided in the LRA and has no additional questions on this item.

B.3.1-2 Your description of the Alloy 600 AMR does not indicate how the review program will satisfy the program attributes defined in Section B.2.2 of Appendix B to the applications. Provide the program attributes, as defined in Section B.2.2 of Appendix B to the applications, for the Alloy 600 AMR.

The applicant characterized that Alloy 600 AMR as a review rather than an aging management program. The applicant also referred the staff to B.3.1, page B.3.1-1, of the LRA, which states that the review will be performed to ensure that nickel-based alloy locations are adequately inspected by the Inservice Inspection Plan or other existing programs such as the Control Rod Drive Mechanism and Other Vessel head Penetration Program, the Reactor Vessel internals Inspection, and the Steam Generator Integrity Program. These programs are actually credited with managing the aging of Alloy 600 locations. The staff is satisfied with this response, but may request the applicant to confirm this information in their written response to a request for additional information.

B.3.1-3 You have not yet conducted the ranking assessment for the nickel-based alloy components within the scope of the Alloy 600 AMR. Provide further details of the modeling methods used to rank the susceptibility of the MNS/CNS nickel-based alloy components within the scope of the Alloy 600 AMR to develop primary water stress corrosion cracking (PWSCC). Upon completion of the ranking assessment, provide the relative PWSCC susceptibility rankings for these components or locations, provide your analysis criteria for deciding whether further/additional inspections are required of these components or locations, and state, for those components for which it is determined that additional inspections are necessary, which of the other AMPs will be used, in conjunction with the A600AMR, to manage PWSCC in these components. Indicate which Alloy 600, 82/182, and 52/152 components, other than the vent nozzle, instrumentation nozzles and CRDM nozzles to the vessel head, will be examined either volumetrically or visually.

The applicant referred the staff to page B.3.1-1, which indicates that the Alloy 600 AMRs will be performed before the end of the current operating licenses for the Catawba and McGuire units, which meets the requirements of 10 CFR 54. The applicant also indicated that, since the review will incorporate plant-specific and industry operating experience, it is more meaningful to perform the review and ranking at that future point in time when the benefit of experience can be more fully realized. The staff is satisfied with this response and rationale and has no additional questions on this issue.

Appendix B, B.3.26, Reactor Vessel Integrity Program

B.3.26-1 The attributes for AMP B.3.26 do not discuss what the applicant will do if proposed changes to the design, withdrawal schedule, testing, or reporting criteria for the Reactor Vessel Integrity Program are not in compliance with the requirements of 10 CFR Part 50, Appendix H. 10 CFR 50.60(b) requires licensees to request exemptions from complying with the requirements of 10 CFR Part 50, Appendix H, if proposed changes to the program are not in compliance with the surveillance capsule design, withdrawal schedule, testing, and reporting requirements of the ASTM Standard Procedure E-182, which is invoked by the rule (i.e., invoked by 10 CFR Part 50, Appendix H). The staff considers this requirement to be important because the staff expects plant-specific reactor vessel material surveillance programs to be in compliance with the requirements of acceptable versions of the standard procedure (the NRC endorses acceptable versions of ASTM Standard Procedure E-182 as the initial version or record or updates to either the 1973, 1977, or 1982 versions of the standard procedure). The administrative controls attribute in AMP B.3.26 does not reflect this requirement. Justify why the administrative controls program attribute for AMP B.3.26 do not reflect this requirement.

The applicant referred the staff to page the Operating Experience discussion, on B.3.26-4 of the LRA, which states that McGuire and Catawba comply with the requirements of 10 CFR 50.60, appendices G and H, and 10 CFR 60.61 through the Reactor Vessel Integrity Program. As such, the requirement that licensees must request such exemptions will be applied through this aging management program as well as the current Part 50 requirements, which will carry forward into the extended period of operation. As such, the staff is satisfied with the information provided in the LRA and has no additional questions on this issue.

B.3.26-2 In Section 4 and Appendix B of the submittal, RT_{PTS} values are estimated for 54 effective full power years (EFPY) of operation. With the current operational record none of the units will attain 54 EFPY in 60 calendar years of operation. Since the license extension request is for 60 calendar years (to satisfy legal requirements) please propose a realistic estimate of the EFPY and the associated vessel quantities i.e. fluence, RT_{PTS} , USE, etc.

The applicant indicated that 54 EFPY bounds more realistic estimates of EFPY. As such, the estimate of 54 EFPY is conservative. The staff is satisfied with this response and understand the rationale. As such, the staff has no additional questions pertaining to this issue.

B.3.26-3 In Table B.3.26-2, the staff notes (for Catawba Unit 1) that the 32 EFPY ID vessel fluence is 2.334 (in terms of 10^{19} n/cm^2). However, the projected value in WCAP-11527, Table 6-11, is 3.17 (no azimuth is specified), in WCAP-13720 Table 6-17, at 25° is 2.52 and in WCAP-15117, Table 6-14 for 34 EFPY is 1.98 at 30°. The updating of the older values should have resulted in higher values. Please explain the apparent discrepancies (projected low leakage loadings) and the physics of the updating which justifies the differences. Why does the maximum occur at slightly different azimuths?

The applicant indicated that this question is appropriate for a request for additional information (RAI). The applicant will submit information to enable the staff to complete its review of this issue in its formal response to the RAI.

B.3.26-4 (for Catawba Unit 2) Same as in Catawba Unit 1 (see RAI B.3.26.2-3), regarding reported values for 32 EFPY in WCAP-11941 and WCAP-13875 vs the submittal Table B.3.26-2. In addition WCAP-13875 does not report calculated values. (Note: in WCAP-11941, Table 6-13 values at 25°, 30° and 45° is there a typo?

Max should be at 25°). Please explain the apparent discrepancies (projected low leakage loadings) and the physics of the updating which justifies the differences. Why does the maximum occur at slightly different azimuths?

The applicant indicated that this question is appropriate for a request for additional information (RAI). The applicant will submit information to enable the staff to complete its review of this issue in its formal response to the RAI.

B.3.26-5 (for McGuire Unit 1) In Table B.3.26-1 of the submittal, a 54 EFPY fluence is reported and referenced to WCAP-14993 which does not include 54 EFPY values. Please explain. The 1/4T value for 32 EFPY reported in WCAP-12354 is significantly different than the value reported in the submittal and referenced to WCAP-12354. Please explain. The value reported in WCAP-10786 for 32 EFPY and the corresponding value reported in the submittal and referenced to WCAP-13949 are significantly different. Please explain. A fluence value is reported in Table B.3.26-1 of the submittal for 54 EFPY of the vessel and referenced to WCAP-14993, which does not report values at 54 EFPY. In addition the value reported for 50.3 EFPY is almost the same. Please explain.

The applicant indicated that this question is appropriate for a request for additional information (RAI). The applicant will submit information to enable the staff to complete its review of this issue in its formal response to the RAI.

B.3.26-6 (for McGuire Unit 2) Table B.3.26-1 of the submittal reports a 54 EFPY value at 1/4T referenced to WCAP-13516 which does not report values above 32 EFPY. How was that value derived? The 1/4T, 32 EFPY value reported in the same table and referenced to WCAP-12556 does not agree with the value reported in the table. Please explain. The 54 EFPY ID value reported in the same table and referenced to WCAP-14799 does not exist in WCAP-14799 which does not report 54 EFPY values. Please explain why. The 32 EFPY ID value reported in the same table was calculated with END/B-IV cross sections in WCAP-13516. In addition justify why this value not reevaluated, especially when the location of the surveillance capsule is behind the neutron pad?

The applicant indicated that this question is appropriate for a request for additional information (RAI). The applicant will submit information to enable the staff to complete its review of this issue in its formal response to the RAI.

Appendix B, B.3.27, Reactor Vessel Internals Inspection Program

B.3.27-1 Examination Category B-N-3, for removable core support structures, is directly applicable to the RVI components. This requires visual VT-3 examination of all accessible parts of the RVI components. Cracks initiated by SSC or fatigue will start off very small and will grow over time. VT-3 examination may not be adequate for detecting cracks before they reach the critical flaw size. The applicant has not identified any augmented inspection programs for detecting such cracking. Describe what supplemental examinations will be performed to detect cracks in RVI components, and provide the technical basis for determining that these supplemental examinations will be capable of detecting the types of cracks expected to occur, before intended function is compromised.

The applicant referred the staff to the Monitoring and Trending section of this program, which describes the inspection activities for various types of RVI components. The staff reviewed this section of the LRA and determined that visual inspection the applicant proposed for difference component types, but may request additional information to confirm that the visual inspection activities that are proposed for this program will be capable of detecting cracks before they reach the critical flaw size.

B.3.27-2 The Reactor Vessel Internals Inspection, as described in LRA Appendix B.3.27, manages cracking due to IASCC and SCC, reduction in fracture toughness due to irradiation and thermal embrittlement, dimensional changes due to void swelling, and loss of preload due to stress relaxation. It will incorporate insights gained from inspections at Oconee and industry activities through EPRI and other industry groups. Aging of RVI components is an issue within the PWR Materials Reliability Project (MRP), and an issue technical group (ITG) has been formed to address aging effects that should be managed. Describe how the results of these industry efforts will be integrated into the plant-specific aging management activities for RVI components. Is Duke participating with the ITG in addressing RVI-related issues?

The applicant responded that Duke is participating in the ITG to address RVI-related issues and that the Reactor Vessel Internals Inspection program is subject to future enhancement as the industry's understanding of degradation mechanisms continues to improve.

B.3.27-3 AMP B.3.27 provides the program attributes for the RVI Program. Under the context of the combined attributes for Monitoring and Trending and Acceptance Criteria, you state that an analysis will be done to determine what the critical size will be CASS internals that could have lowered fracture toughness values as a result of thermal and irradiation embrittlement, and that the types of inspections to manage cracking in these components will depend on the results of the analysis. Since this analysis will not be implemented and the results evaluated prior to completion of the staff's review period for the application, the staff needs to know what commitments you are implementing to ensure that this analysis will be completed in a timely fashion and that sufficient inspection techniques will be proposed to monitor for cracking of these CASS internals. Discuss what commitments you made or will make to provide your analysis results and inspection methods for detecting cracking in the CASS internals to the staff for evaluation once the analysis is completed and provide an expanded discussion of the possible inspection techniques that may be used to monitor for cracking in these components during the periods of extended operation for the units.

The applicant responded that any commitments made provide analysis results and inspection methods for detecting cracking in the CASS internals to the staff for evaluation once the analysis is completed will be documented in the UFSAR Supplements for McGuire and Catawba. Additionally, the applicant suggested that an expanded discussion of the possible inspection techniques that may be used to monitor for cracking in these components during the periods of extended operation for the units is not meaningful at this time because the merit of the particular analysis that will be adopted for the extended period of operation is material to the staff's review. As such, the staff will have an opportunity to compare the applicant's commitment to the adopted analysis at the appropriate point in the future before the expiration dates of the current operating licenses. The staff is satisfied with this response and agrees that, if renewed operating licenses are issued for Catawba and McGuire, the licenses will specify the dates that the commitments made (as documented in the UFSAR Supplements) will be in full effect. The staff has no additional questions on this item.

B.3.27-4 The applicant has identified change in dimensions due to void swelling as an applicable aging effect; it will be managed by the Reactor Vessel Internals Inspection. In Section B.3.27 "Monitoring and Trending", the applicant states that McGuire and Catawba will rely upon the results of the inspections at Oconee to assess the effects of void swelling. It is not clear to the staff whether the Oconee results will be applicable to McGuire and Catawba, because the RVI components are of different designs (B&W vs. Westinghouse), may utilize different materials of construction, and may be subject to different fluence rates. Provide additional information that supports the technical validity of this extrapolation, specifically addressing the similarities and differences pertaining to RVI design details; materials of construction; reactor power rating and neutron fluence levels; and critical locations where dimensional changes may compromise performance of intended functions.

The applicant indicated that this question is appropriate for a request for additional information (RAI). The applicant will submit information to enable the staff to complete its review of this issue in its formal response to the RAI.

B.3.27-5 Loose parts monitoring and neutron noise monitoring provide indications of RVI component degradation during plant operation, and are potentially valuable adjuncts to periodic ISI, to detect conditions such as core barrel vibration, component wear, or relaxation of the hold down spring and clevis insert bolts on a continual basis. The applicant does not credit any supplemental monitoring activities to detect degradation during plant operation under the monitoring and trending attribute. Describe the monitoring activities currently conducted at McGuire and Catawba, such as loose parts and neutron noise monitoring, and explain how these activities will be factored into aging management of RVI components.

The applicant requested the staff to specify how the program credited in the LRA to manage the aging of RVI was inadequate. The staff could not make that argument that the applicant proposed aging management programs were deficient in some manner. As such, the staff has no additional questions on this issue.

Appendix B, B.3.31, Steam Generator Surveillance Program

B.3.31-1 In Section B.3.31 of Appendix B of the application, the applicant describes steam generator operating experience at the McGuire and Catawba sites. The most common degradation effect was found to be wear at the secondary side U-bend fan bars. The applicant states that the current wear rate for the Westinghouse model D5 steam generators is less than 5% per cycle for anti-vibration bars and pre-heater tubes based on a review of eddy current data. The staff believes that a wear rate of this magnitude may eventually lead to excessive tube vibration and loss of function for the anti-vibration bars. Clarify whether the current wear rates for the anti-vibration bars and pre-heater tubes are acceptable, or if additional corrective actions are needed to minimize the wear rates for these components.

The applicant indicated that they considered the wear rate acceptable to the extent that the acceptance criteria of the Steam Generator Surveillance Program would be met and requested the staff to specify why a current wear rate of less than 5% per cycle was unacceptable or significant. The staff has no additional questions on this issue.

4.2.1, Upper Shelf Energy (USE) Assessments
4.2.2, Pressurized Thermal Shock (PTS) Assessments

The staff performed independent reviews of the USE and PTS data for license renewal using the staff's local version of the NRC's Reactor Vessel Database and identified differences in the data. The staff also concluded that USE and PTS data had not been provided to the NRC on the reactor vessel beltline nozzle materials. The staff has requested additional information pertaining to PTS and USE assessments of vessel beltline nozzle materials to complete its review of LRA Sections 4.2.1 and 4.2.2. The staff and applicant agreed that both sets of data indicate that all reactor vessel beltline materials (with the exception of reactor vessel beltline nozzle materials) currently meet the requirements of 10 CFR 50.61 and 10 CFR 50 Appendix G and will continue to meet these requirements during the extended period of operation. Since the data discrepancies do not prevent the staff from making a reasonable assurance finding in its review of the LRA, the staff will pursue resolution of the data discrepancies as they relate to current plant operation.

A draft of this telecommunication summary was provided to the applicant to allow them the opportunity to comment prior to the summary being issued.

/***RA***/

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

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pertaining to PTS and USE assessments of vessel beltline nozzle materials to complete its review of LRA Sections 4.2.1 and 4.2.2. The staff and applicant agreed that both sets of data indicate that all reactor vessel beltline materials (with the exception of reactor vessel beltline nozzle materials) currently meet the requirements of 10 CFR 50.61 and 10 CFR 50 Appendix G and will continue to meet these requirements during the extended period of operation. Since the data discrepancies do not prevent the staff from making a reasonable assurance finding in its review of the LRA, the staff will pursue resolution of the data discrepancies as they relate to current plant operation.

A draft of this telecommunication summary was provided to the applicant to allow them the opportunity to comment prior to the summary being issued.

/***RA***/

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