3.4.3.2 Staff Evaluation

The staff reviewed the information included in LRA Section 3.1.3 (including Tables 3.1.3-1 and 3.1.3-W1), and pertinent sections of LRA Appendices A and B, as supplemented by the RAI responses. In addition to the applicable sections contained in the LRAs, topical report WCAP-14577, Rev. 1-A, and the staff's FSER on the topical report were also reviewed to determine that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation for the RV internals.

The applicant addressed all renewal applicant action items that are included in the FSER for WCAP-14577, Rev. 1-A in LRA Table 3.1.3-W1 for both plants. There are 11 action items in the staff's FSER on WCAP-14577, Rev.1-A.

Action Items from Previous Staff FSER for WCAP-14577, Rev.1-A

From its review of this information, the staff finds that the applicant's response to the 11 "Renewal Applicant Action Items" resolve the applicant action items in the FSER for WCAP-145777, Rev.1-A. The action items, applicant's responses, and staff's evaluations are provided in the following paragraphs.

- Item 1: To ensure applicability of the results and conclusions of WCAP-14577 to the applicant's plant(s), the license renewal applicant is to verify that the critical parameters for the plant are bounded by the topical report. Further, the renewal applicant must commit to programs described as necessary in the topical report to manage the effects of aging during the period of extended operation on the functionality of the reactor vessel components. Applicants for license renewal will be responsible for describing any such commitments and proposing the appropriate regulatory controls. Any deviations from the aging management programs described in this topical report as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel internal components or other information presented in the report, such as materials of construction, must be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).

  Response: As discussed in Section 3.1.3, Reactor Vessel Internals, the RV internals are bounded by the topical report with regard to design criteria and features, material of construction, fabrication techniques, installed configuration, mode of operation and environments/exposures. The programs necessary to manage the effects of aging are identified in Table 3.1.3-1, Reactor Vessel Internals, and described in Appendix B.

  The applicant has reviewed the current designs and operation of the RV internals, and has determined that the internals are bounded by the descriptions contained in WCAP-14577 with the exception of the flux thimble tubes, which are evaluated for the effects of aging with the RV (see Section 3.1.2 of the LRAs). The applicant's AMPs for the RV internals are described in Appendix B of the LRAs. The staff evaluation of these AMPs is provided in Section 3.3.1.15 of this SER. The staff finds this to be acceptable.

- Item 2: A summary description of the programs and activities for managing the effects of aging and the evaluations of TLAA's must be provided in the license renewal FSAR supplement in accordance with 10 CFR 54.21(d).

  Response: A summary of the programs identified to manage the effects of aging and the evaluation of TLAAs for the RV internals is provided in the UFSAR supplement in Appendix A. The staff finds this to be acceptable.

- Item 3: For the holddown spring, applicants for license renewal are expected to address intended function, aging management review, and appropriate aging management program(s).

  Response: The holddown spring is in-scope for the RV internals. The results of the AMR for the RV internals are provided in Section 3.1.3 and summarized along with the intended function and the programs necessary to manage the effects of aging in Table 3.1.3-1, Reactor Vessel Internals. A description of these programs is provided in Appendix B.

  The applicant has included the passive function of the holddown spring in Section 3.1.3 of the LRAs. In Section B4.0 of the LRAs, the applicant has included an augmented inspection activities as one of the Licensee Follow-up Actions which suggests that the core barrel hold-down springs will be inspected for the loss of pre-load and the initial inspection will be performed prior to the end of the current operating license. The staff finds this to be acceptable.

- Item 4: The license renewal applicant must address aging management review, and appropriate aging management program(s), for guide tube support pins.

  Response: The guide tube support (split) pins are in-scope for the RV internals. The results of the aging management review for the RV internals are provided in Section 3.1.3 and summarized along with the intended function and the programs necessary to manage the effects of aging in Table 3.1.3-1, Reactor Vessel Internals. A description of these programs is provided in Appendix B.

  The applicant has identified the two AMPs associated with the control rod guide tube split pins in Table 3.1.3-1 of the LRA, and provided a description of these two AMPs in Appendix B. As noted in the topical report, Surry 2 has not upgraded to the new material, and Surry 1 has a different support pin design by Framatome, which is excluded from the topical report requiring plant-specific actions, as indicated in Section 2.6.7.2 of the topical report, WCAP-145777, Rev.1-A. The Surry 2 support pin is the original design which was a pre-stressed tensile design to perform its intended function. The staff issued an RAI to further understand how aging of these support pins will be managed throughout the period of extended operation. In response to the RAI Item 3.1.3.2-2, the applicant stated that the cracking of these control rod guide tube split pins is managed by the chemistry control program and the RV internals inspection activities. Based on these considerations, the staff found the applicant's identification of the AMPs for the guide support pins to be acceptable.

- Item 5: The license renewal applicant must explicitly identify the materials of fabrication of each of the components within the scope of the topical report. The applicable aging effects should be reviewed for each component based on the materials of fabrication and the environment.

  Response: The materials for each in-scope RV internals along with aging effects and environments are identified in Table 3.1.3-1, Reactor Vessel Internals. A description of these programs is provided in Appendix B.

  The applicant has identified the material of fabrication for the RV internals in Section 3.1.3 (Table 3.1.3-1) of the LRAs. This table also identifies the applicable aging effects. The staff finds this to be acceptable.

- Item 6: The license renewal applicant must describe its aging management plans for loss of fracture toughness in cast austenitic steel RV internals components, considering the synergistic effects of thermal aging and neutron irradiation embrittlement in reducing the fracture toughness of these components.

  Response: The program necessary to manage the reduction of fracture toughness in cast austenitic stainless steel RV internals is described in Appendix B, Reactor Vessel Internals Inspection.

  The applicant has identified the RV internals inspection program in Appendix B of the LRAs, as the program to manage the loss of fracture toughness in cast austenitic stainless steel reactor vessel internal components. The staff issued an RAI to further clarify the applicant's plan to manage this aging effect. In response to RAI Item 3.1.3.2-3, the applicant stated that the aging management activities in this program will be identified as a follow-up action item to monitor industry initiatives under EPRI's Materials Reliability Program. The applicant will implement the NRC-approved industry activities resulting from this program, as appropriate. The staff finds this response to be acceptable.

- Item 7: The license renewal applicant must describe its aging management plans for void swelling during the license renewal period.

  Response: A license renewal industry position on void swelling is being developed. The applicant will follow this issue and evaluate appropriate changes to the reactor vessel internals inspection, as identified in Appendix B, once an industry position has been established.

  Section 3.2.10 of the final SER on topical report WCAP-14577, Rev. 1-A states that the staff considers void swelling to be a significant issue. References cited predict swelling as great as 14% for PWR baffle-former assemblies. Although in LRA Section C3.9.1 of the LRA it is stated that there is not any evidence of, or any discernable effects attributable to void swelling, the applicant has stated in LRA Section B2.2.15 that it will remain cognizant of industry developments on the void swelling issue, and evaluate any appropriate changes to the reactor vessel internals inspection AMP once an industry position is established. The staff finds this to be acceptable.

- Item 8: Applicants for license renewal must describe how each plant-specific AMP addresses the following elements: (1) scope of the program, (2) preventative actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

  Response: The programs necessary to manage the effects of aging for the RV internals addresses the 10 elements identified. These programs are identified in Table 3.1.3-1, Reactor Vessel Internals, and described in Appendix B.

  The applicant states that the two AMP's designated to manage aging for the RV internals, the chemistry control program for primary systems and the reactor vessel internals inspection program, as described in Appendix B of the LRAs, adequately address the ten elements identified. The staff evaluation for these two AMPs applicable to RV internals may be found in Sections B2.2.4 and B2.2.15. The staff finds this to be acceptable.

- Item 9: The license renewal applicant must address plant-specific plans for management of cracking (and loss of fracture toughness) of reactor vessel internal components, including any plans for augmented inspection activities.

  Response: The programs necessary to manage cracking and reduction of fracture toughness are identified in Table 3.1.3-1, "Reactor Vessel Internals," and described in Appendix B.

  The applicant has identified two AMPs, the chemistry control program for primary systems and the reactor vessel internals inspection program (as described in Appendix B of the LRAs), as adequate to manage cracking and loss of fracture toughness. As discussed in Section 3.3.1 of the FSER for topical report WCAP-14577, Rev.1-A, the visual VT-3 examination required by Examination Category B-N-3 may not be adequate to detect cracking of the susceptible reactor vessel internal components. The examination technique used must be capable of detecting the types of cracking expected to occur. The staff concludes that augmented inspection is warranted for cracking and loss of fracture toughness. As noted in Table 4-2 of the topical report, the ASME Section XI Examination, as supplemented when relevant conditions are detected (IWB-3142), can manage the effects of irradiation embrittlement for components even though the fluence levels for 60 years of total service may exceed the threshold fluence level for the material of construction. The staff issued an RAI to further understand how cracking will be managed during the period of extended operation. In response to RAI 3.1.3.2-4, the applicant stated that NRC-approved industry activities resulting from the EPRI Materials Reliability Program initiatives, as appropriate, will be implemented to manage the aging effects associated with RV internals. The staff finds this to be acceptable.

- Item 10: The license renewal applicant must address plant-specific plans for management of age-related degradation of baffle/former and barrel/former bolting, including any plans for augmented inspection activities.

Response: The programs necessary to manage age-related degradation of baffle/former and barrel/former bolting are identified in Table 3.1.3-1, "Reactor Vessel Internals," and described in Appendix B.

European plants identified the cracking of baffle former bolts in 1988. The materials and design of the reactor vessel internals (RVI) of these plants, including the baffle former bolting, are similar to those of the domestic Westinghouse plants. At the foreign plants, ultrasonic examination was performed to identify baffle bolt cracking. Historically, baffle bolt cracking has not been identified as an issue for domestic plants.

Domestic plant RVI baffle former bolts are subject to the visual examination requirements of the ASME B&PV Code, Section XI. However, the baffle bolt cracking occurs at the juncture of the bolt head and shank, which is not accessible for visual inspection. The NRC issued Information Notice 98-11, "Cracking of Reactor Vessel Internals Baffle Bolts in Foreign Plants," on March 25, 1998, to alert licensees to this baffle bolt cracking experience.

The Westinghouse Owners Group (WOG) had periodic meetings and interactions with the staff from 1997 to the present regarding its ongoing programs and activities to resolve the baffle bolt cracking issue. The ongoing programs and activities include (1) development and approval of a prescribed analytical methodology for evaluating the acceptability of baffle bolting distributions under faulted conditions, (2) assessment of the safety significance of potentially degraded baffle bolting, (3) baffle bolting inspections, replacements, and testing at lead plants, and, (4) development of inspection monitoring activities and aging management programs. The first three activities have been completed. The current WOG activities include evaluation of the results of the ultrasonic examination of integrity of the baffle former bolts in four WOG plants, and the hot cell evaluation of baffle bolts removed from three of the Westinghouse plants. The WOG continues to meet with the staff periodically to present status reports on these activities.

The applicant has identified two AMPs, the chemistry control program for primary systems and the RVI inspection program (as described in Appendix B of the LRA), as adequate to manage aging effects on baffle/former and barrel/former bolting. Section 3.3.4 of the FSER for topical report WCAP-14577, Rev. 1-A states that VT-3 examinations alone will not detect cracking in these bolts. Augmented inspections, such as ultrasonic inspections, are proposed in the FSER to provide effective management of the effects of aging on these bolts.

The applicant has committed to a one-time focused inspection of the internals to check for all aging effects, applying the leading indicator approach. The leading indicator approach will be based on several factors such as fluence, stress, and material susceptibility. The inspection will be performed between year 30 and the end of the term of the current operating license on the single Surry or North Anna reactor determined to be the most susceptible to the identified aging effects. The inspection results will determine the need for inspection of the other reactors.

In addition, in response to RAI Item 3.1.3.2-5, the applicant stated that the NRC-approved industry activities resulting from the EPRI's Materials Reliability Program initiatives, as appropriate, will be implemented to manage the aging effects associated with barrel/former and baffle/former bolting. In response to RAI 3.1.3.2-5, the applicant stated that the NRC-approved industry activities resulting from the EPRI's Materials Reliability Program initiatives, as appropriate, will be implemented to manage the aging effects associated with barrel/former and baffle/former bolting.

- Item 11: The license renewal applicant must address the TLAA of fatigue on a plant-specific basis.

  Response: The reactor internals were designed and fabricated before the existence of Subsection NG (Core Structures) of the ASME Code. The criterion utilized by Westinghouse for pre-1974 plants was developed internally within Westinghouse and is similar to the subsection NG requirements since many of the Westinghouse designers were members of the ASME code committee that developed the NG subsection. No ASME code design or stress report was required and therefore does not exist for those reactor internals.

  To assess the acceptability of the RV internals relative to fatigue for the period of extended operation, the methodology of WCAP-14577 was followed. The preferred approach is to demonstrate that the fatigue effects anticipated for the license renewal term are bounded by the fatigue effects anticipated for the original service period. It is projected that the number of transients for 60 years, including period of extended operation will be less than the design transients. All significant transients will be monitored as described in Section B3.2, Transient Cycle Counting. This will assure that the transients for 60 years will be within design values. The staff finds this to be acceptable.

3.4.3.2.1 Aging Effects

In Section 3.1.3 and Table 3.1.3-1 of the LRA, the applicant identifies the following aging effects associated with the RV internals:

- cracking
- loss of material
- loss of pre-load
- reduction in fracture toughness

Specific discussions for each of these aging effects was discussed in Section C3.0 of the LRAs. Section 3.2 of the FSER on Topical report WCAP-14577, Rev. 1-A discusses the aging mechanisms and effects for the RV internals.

In addition to those identified by the applicant, neutron irradiation embrittlement, creep, wear, and fatigue were also identified as aging mechanisms by the topical report. The applicants position on the neutron irradiation effect was discussed in detail in the LRAs. Though the staff did not agree with the neutron fluence threshold used to screen components, the staff found that it did address those components with the highest fluences. In response to RAI Item 3.1.3.2.1-1(a), the applicant has added the lower support plate as susceptible to loss of fracture toughness due to neutron embrittlement. The applicant in Section C3.5.2 states that this aging mechanism has been evaluated during the AMRs. For stainless steel alloys and nickel-based alloys, creep is not a concern at PWR conditions with temperatures below 537.8°C (1000°F). However, the topical report indicates that irradiation creep can be caused by defects that result from neutron flux exposure. Therefore, the baffle/former and barrel/former bolting are identified as susceptible to loss of preload as an applicable aging effect. Wear, while not a significant aging effect for most RV internals, can be potentially significant at interfaces of components which have relative motion. The applicant in Sections 3.1.3 and C3.1.7 of the LRAs states that it was found not to be an aging effect requiring aging management. However, in response to RAI Item 3.1.3.2-1, the applicant stated that loss of material due to wear for RV internals in-scope components is managed by the RV internals inspection program.

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

3.4.3.2.2 Aging Management Programs

Section 4.0 of topical report WCAP-14577 Rev. 1-A discusses aging management activities and program attributes applicable to RV internals. Tables 4-2, 4-3, 4-5, and 4-6 in this topical report provide this information for specific aging mechanisms (e.g., IASCC, stress relaxation, wear, and fatigue). Table 4-4 provides the aging management activities attributable for wear in BMI flux thimbles. Tables 4-7 and 4-8 provide additional activities and program attributes for the aging management of baffle/former bolts and core barrel/former bolts respectively.

The applicant identifies two AMPs used to manage the effects of aging for the RV internals:

- chemistry control program for primary systems
- reactor vessel internals inspection

The staff's evaluation of the applicant's AMPs focused on the program elements rather than details of specific plant procedures.

Chemistry control program for primary systems, as stated by the applicant in Section B2.2.4 of the LRAs, is to provide reasonable assurance that the reactor water quality is compatible with the materials of construction in the plant systems and equipment in order to minimize loss of material and cracking. The RV internals is listed as a major component applicable to this AMP. This AMP is based upon Technical Specifications and the EPRI guidelines provided in Technical Report TR-105714. The EPRI guidelines reflect industry operating experience and are revised as necessary to optimize plant chemistry control. The staff's evaluation of this AMP is provided in Section 3.3.1.4 of this SER.

Reactor vessel internals inspection, as discussed in Section B2.2.15 of the LRAs, is primarily comprised of the inservice inspection program, a one time focused inspection of the RV internals, and an augmented inspection activity as part of the licensee follow-up actions for the core barrel holddown spring. The staff's evaluation of this AMP is provided in Section B2.2.15.

On the basis of the evaluation of the AMPs identified above, the staff concluded that these AMPs are acceptable for managing the pertinent aging effects and providing assurance that the intended functions of the RV internals will be maintained consistent with the CLB throughout the period of extended operation.

3.4.3.3 Conclusions

The staff has reviewed the information on AMPs given in Section 3.1.3 "Reactor Vessel Internals," and Appendix B of the LRA, as supplemented by applicant's RAI responses. On the basis of this review, the staff concludes that the applicant has demonstrated that the effects of aging associated with the RV Internals will be adequately managed such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

3.4.4 Pressurizers

One pressurizer per RV is connected to the RCS hot leg piping via the surge line and the cold leg piping via the spray line. The spray line and surge line nozzles are provided with thermal sleeves. The internal surfaces of the pressurizer are clad with stainless steel which provides corrosion resistance to the borated coolant water. Access is provided by a manway opening near the top of the pressurizer. During normal operation, the pressurizer contains a combination of borated reactor coolant and steam that is maintained at the desired temperature and pressure by the electric heaters and pressurizer spray system. The chemical and volume control system maintains the desired water level in the pressurizer during steady-state operation. Section 2.3.1.4 of the LRAs gives a general description of the North Anna and Surry pressurizers, which are designed in accordance with the ASME Code, Section III.

The pressurizer is designed to accommodate insurges and outsurges caused by the power load transients. During an insurge, the spray system condenses steam to prevent the pressure reaching the operating point of the power-operated relief valve. A continuous spray flow is provided to ensure that the water chemistry within the pressurizer is consistent with that in the RCS. During an outsurge, water flashes to steam due to the resulting pressure reduction and the automatic actuation of the heaters to keep the pressure above the minimum allowable limit.

The applicant states that the intended function of the pressurizer is to maintain the structural integrity of the reactor coolant pressure boundary. Another intended function for certain pressurizer subcomponents is to provide support for maintaining the integrity of pressure boundary components.

3.4.4.1 Summary of Technical Information in the Application

Table 2.3.1-4 of the LRAs lists the passive functions of each pressurizer subcomponent. Twenty-one subcomponents are specified, and all but two have an intended function of maintaining the pressure boundary. The remaining two (seismic support lugs and the support skirt/flange) have the intended function of providing structural and/or functional support for in-scope equipment.

Section 3.1.4 of the LRAs provides an aging management review of the pressurizers, which is summarized in Table 3.1.4-1. The table provides the following information for each subcomponent: (1) the passive function, (2) the material group, (3) the environment, (4) the aging effects requiring management, and (5) the specific aging management activities used for managing these aging effects.

In addition, the Westinghouse Owners Group Life Cycle Management & License Renewal Program has prepared a topical report, WCAP-14574-A, "Aging Management Evaluation for Pressurizers," which is used as the primary reference for developing the aging management review for the pressurizer. The FSER for WCAP-14574-A was issued by letter dated October 26, 2000. In Section 3.1.4 of the LRAs, the applicant states that the scope of the pressurizer described in the topical report bounds the North Anna and Surry pressurizers with the following clarifications:

- the topical report assumes the primary system chemistry control program is in place and does not recognize the program in the management of loss of material or cracking from stress corrosion. For the aging management review of the North Anna and Surry pressurizers, the chemistry control program for primary systems manages these aging effects.

- in general, cracking of pressurizer subcomponents (regardless of aging mechanism) is managed by the ISI program - component and component support inspections.

- the topical report does not recognize loss of pre-load due to stress relaxation as an aging effect requiring management. For the North Anna and Surry pressurizers, loss of pre-load is considered to be an aging effect and is managed by the ISI program - component and component support inspections.

- in the topical report, nickel-based alloy (Alloy 82/182), which is used to butter pressurizer surge, spray, relief and safety nozzles, is not considered to require aging management. In the LRA, the applicant stated that cracking of nickel-based alloys in pressurizers is considered to be an aging effect requiring management, and is managed with the chemistry control program for primary systems.

- in the topical report, the stress corrosion cracking of sensitized stainless steel nozzle safe ends is considered to be an aging effect that is managed by ASME Section XI inspections. In the Surry LRA, the stress corrosion cracking is managed by the chemistry control program for primary systems in addition to the ASME Section XI inspections.

- for Surry, stress corrosion cracking of instrument and sample nozzles is an aging effect managed by the augmented inspection activities program. The topical report does not identify any equivalent aging management program.

- the topical report does not recognize boric acid corrosion of the pressurizer as an aging effect. However, the applicant considers boric acid wastage as an aging effect managed by the boric acid corrosion surveillance program.

- with the exception of SCC/PWSCC, the topical report does not identify any additional corrosion mechanisms for stainless steel in treated water and/or steam environment. The applicant believes that crevice corrosion/under deposit attack and pitting corrosion require aging management for stainless steel in treated water. These aging mechanisms are managed by the chemistry control program for primary systems.

- the topical report identifies valve support bracket lugs as subcomponents within the scope of license renewal. However, the applicant points out that their pressurizers do not have this subcomponent.

Section 3.1.4 of the LRAs also includes a general description of pressurizer materials, and pressurizer internal and external environments. The North Anna pressurizer surge, spray, relief, and safety nozzles were buttered with nickel-based alloy (Alloy 82/182). The Surry pressurizer safe ends and welds were exposed to post-weld heat treatment (PWHT), which resulted in sensitization of the stainless steel material. The internal environments include treated (borated) water and steam. The external environments include air as well as borated water at coolant leakage points in the pressurizer.

3.4.4.1.1 Aging Effects

In Table 3.1.4-1 of the LRAs, the applicant, in accordance with 10 CFR 54.4(a), has identified the following two intended functions applicable to the pressurizer and associated subcomponents:

- provide a pressure boundary (19 subcomponents)
- provide structural and/or functional support for in-scope equipment (seismic support lugs, and support skirt/flange)

The aging effects associated with the pressurizer and its subcomponents that require aging management are listed in Section 3.1.4 of the LRAs and include:

- cracking of carbon steel and low-alloy steel subcomponents in an air environment and cracking of stainless steel in a treated water/steam environment
- cracking and loss of material in nickel-based subcomponents in a treated water/steam environment for North Anna
- cracking and loss of material in sensitized stainless steel components in air and treated water environments for Surry
- loss of material from stainless steel subcomponents in a treated water/steam environment
- loss of material from carbon steel and low-alloy steel subcomponents in a borated water leakage environment
- loss of pre-load of the pressurizer low-alloy steel manway bolting

3.4.4.1.2 Aging Management Programs

In Section 3.1.4 of the LRAs, the applicant listed the AMPs for managing pressurizer aging effects. The aging effects for the pressurizer subcomponents are given in Table 3.1.4-1 of the LRAs as cracking, loss of material, and loss of pre-load. In this Table and in Section 3.1.4 of the LRAs, the licensee lists the applicable AMPs for managing these effects associated with pressurizers and they are given as:

- chemistry control program for primary systems.

- ISI program - component and component support inspections.
- boric acid corrosion surveillance.
- augmented inspection activities for Surry

These programs are described in more detail in Appendix B of the LRA.

The applicant concludes that, based on the demonstrations of the AMPs in Appendix B and the TLAA in Section 4.0 of the LRA, the aging effects associated with the pressurizer subcomponents will be adequately managed so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

In addition, the LRA specifies "Metal Fatigue" as an applicable TLAA associated with the pressurizer.

3.4.4.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3) and (c)(1), the staff reviewed the information in Section 3.1.4 (including Tables 3.1.4-1 and 3.1.4-W1), pertinent sections of LRA Appendices A and B, and the staff's FSER on the topical report WCAP-14574-A. The review was performed to verify that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation for the pressurizer subcomponents.

The applicant addressed all renewal applicant action items that are included in the FSER for WCAP-14574, Rev. 1-A, in LRA Table 3.1.4-W1 for both stations. There are 10 action items in the staff's FSER on WCAP-14574, Rev.1-A.

<u>Action Items from Previous Staff FSER for WCAP-14574, Rev.1-A</u>

From its review of this information, the staff finds that the applicant's response to the 10 "Renewal Applicant Action Items" resolve the applicant action items in the FSER for WCAP-14574, Rev.1-A. The action items, applicant's responses, and staff's evaluations are provided in the following paragraphs.

- Item 1: License renewal applicants should identify the TLAAs for the pressurizer components, define the associated CUF and, in accordance with 10 CFR 54.21(c)(1), demonstrate the TLAAs meet the CLB fatigue design criterion, CUF < 1.0, for the extended period of operation, including the insurge/outsurge and other transient loads not included in the CLB, which are appropriate to such an extended TLAA, as described in the WOG report "Mitigation and Evaluation of Thermal Transients Caused by Insurges and Outsurges," MUHP-5060/5061/5062, and considering the effects of the coolant environment on critical fatigue locations. The applicant must describe the methodology used for evaluating insurge/outsurge and other off-normal and additional transients in the fatigue TLAAs.

  Response: The pressurizer TLAA evaluation is provided in Section 4.3, Metal Fatigue.

The licensee stated, in Section 4.3.1 of the LRAs, that in response to NRC Bulletin 88-11 the pressurizer surge lines were analyzed for the insurge/outsurge event, which imposed thermal loads not considered in the original analyses.

The staff has separately reviewed the issue of environmentally-assisted fatigue in Section 4.3 of this SER. The applicant has conducted a separate analysis to determine whether additional actions will be needed during the period of extended operation. Part of this new analysis was to determine the most fatigue-sensitive subcomponents in the North Anna and Surry plants. Among these was the pressurizer surge line, including the pressurizer and hot leg nozzles. Using data from NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Design Curves to Selected Nuclear Power Plant Components," and NUREG/CR-6583, "Effect of LWR Coolants on the Fatigue Design Curves of Carbon and Low-Alloy Steels," the applicant has scaled up the plant-specific CUF for fatigue-sensitive locations for the pressurizers (as well as other components) to account for environmental effects. Based on these adjustments, the applicant states that only the pressurizer surge line piping requires further evaluation for the period of extended operation. In lieu of additional analyses to refine the CUF for the surge line, the applicant has opted to implement an AMP to address surge line fatigue failure during the period of extended operation. Specifically, the surge line weld at the hot leg pipe connection will be examined in an augmented inspection program. This will, according to the applicant, provide reasonable assurance that the potential reactor water environmental effects will be managed such that components within the scope of license renewal will continue to perform their CLB function during the period of extended operation. The augmented inspection activities in Section B2.2.1 of the LRA do not include the pressurizer surge line for checking fatigue cracking. However, the applicant has identified this in Section B4.0 of the LRA as one of the licensee follow-up actions. The staff finds this to be acceptable.

- Item 2: In the report, WOG concluded that general corrosion is nonsignificant for the internal surfaces of Westinghouse-designed pressurizers and that no further evaluations of general corrosion are necessary. While the staff concurs that hydrogen overpressure can mitigate the aggressive corrosive effect of oxygen in creviced geometries on the internal pressurizer surfaces, applicants for license renewal will have to provide a basis (statement) in their plant-specific applications about how their water chemistry control programs will provide a sufficient level of hydrogen overpressure to manage general corrosion of the internal surfaces of their pressurizers.

  Response: A hydrogen overpressure is maintained in the volume control tanks to minimize general corrosion in the reactor coolant system, as well as the pressurizer. The chemistry control program for primary systems is based on EPRI document TR-105714 (PWR Primary Water Chemistry Guidelines). These guidelines establish strict limits on hydrogen concentration, which are verified through periodic sampling. The hydrogen overpressure, in combination with stainless steel cladding of components, ensures that general corrosion is a non-significant aging mechanism. The chemistry control program for primary systems is described in Appendix B.

  The staff finds this response to be acceptable since the applicant is adhering to industry-recommended guidelines on acceptable hydrogen overpressure limits.

- Item 3: The staff finds that the criteria in GL 88-05 and the Section XI requirements for conducting leak tests and VT-2 type visual examinations of the pressurizer boundary are acceptable programs for managing boric acid corrosion of the external, ferritic surfaces and components of the pressurizer. However, the report fails to refer to the actual provisions in the ASME Code, Section XI that require mandatory system leak tests of the pressurizer boundary. The applicants must identify the appropriate Code inspection requirements from ASME Code Table IWB-2500-1.

  Response: Mandatory leak testing of the pressurizers is specified by ASME Section XI, Subsection IWB, Table IWB-2500-1, Category B-P. The staff finds this response to be acceptable.

- Item 4: The staff concurs that the potential to develop SCC in the bolting materials will be minimized if the yield strength of the material is held less than 150 ksi, or the hardness is less than 32 on the Rockwell C hardness scale; however, the staff concludes that conformance with the minimum yield strength criteria in ASME Specification SA-193, Grade B7, does not in itself preclude a quenched and tempered low-alloy steel from developing SCC, especially if the acceptable yield strength is greater than the acceptable yield strength of 150 ksi. To take credit for the criteria in EPRI Report NP-5769, the applicant needs to state the acceptable yield strengths for the quenched and tempered low-alloy steel bolting materials (e.g., SA-193 Grade B, materials) are in the range of 105-150 ksi.

  Response: SCC of bolting is addressed in Appendix C.

  The staff finds that this action item is not fully addressed in Section C3.2.1 of the LRA on bolting. The applicant stated that the yield strength of low-alloy steel bolting has been measured, and found to be less than 150 ksi. However, in response to RAI Item 3.1.4.2-1, the applicant stated that all Grade B7 materials were purchased in accordance with the requirements of SA-193 under 10 CFR 50, Appendix B, procurement program. Because bolting procurement program met the requirements of 10 CFR Part 50, Appendix B, the staff finds this response to be acceptable.

- Item 5: The staff considers the discussion in Section 3.5.2 to be extremely confusing in that it appears WOG is making three different conclusions that conflict with one another:

  a. That fluid velocity and particulate conditions are not sufficient in the pressurizer to consider that erosion is a plausible degradation mechanism that could affect the integrity of subcomponents in the pressurizer.

  b. That several components in the pressurizer (refer to the list above) are exposed to fluid flows that have the potential to result in erosion of the components.

  c. That only one component in the pressurizer (the spray head) is exposed to a fluid flow that has the potential to result in erosion of the component.

  The applicant should state why erosion is not plausible for the surge nozzle thermal sleeve, spray nozzle thermal sleeve, surge nozzle safe-end, and spray nozzle safe-end. If erosion is plausible, then an AMP is required.

Response: The relatively low flow velocity in the spray and surge line thermal sleeves and safe ends, combined with the use of stainless steel materials and limited particulate matter in the system, ensured that the loss of material due to erosion is not an aging effect requiring aging management. Since erosion does not occur in low flow velocity locations, the staff finds this response to be acceptable.

- Item 6: Applicants for license renewal must describe how each plant-specific AMP addresses the following 10 elements: (1) scope of the program, (2) preventive action, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, (10) operating experience.

  Response: The programs necessary to manage the effects of aging for the pressurizer address the 10 elements identified. These programs are identified in Table 3.1.4-1, Pressurizers, and described in Appendix B. The staff finds this response to be acceptable.

- Item 7: Applicants for license renewal must provide sufficient details in their LRAs about how their GL 88-05 programs and ISI programs will be sufficient to manage the corrosive effects of boric acid leakage on their pressurizer components during the proposed extended operating terms for their facilities, including postulated leakage from the pressurizer nozzles, pressurizer nozzle-to-vessel welds, pressurizer nozzle safe end welds, and pressurizer manway bolting materials.

  Response: Boric acid wastage is an aging mechanism requiring management of the external surfaces of the pressurizers. The boric acid corrosion surveillance activity is credited with managing boric acid wastage. The system pressure test specified by ASME Section XI, Subsection IWB, Table IWB-2500-1, Category B-P may also be used to detect pressurizer leakage. The boric acid corrosion surveillance activity and the ISI program - component and component support inspections are described in Appendix B. Included in the description is a demonstration of program effectiveness.

  The staff, in its review of the boric acid corrosion surveillance AMP in Section 3.3.1.3 of this SER, notes that it involves visual examination of the pressurizer surfaces for evidence of coolant leakage. In addition, the ISI program - component and component support inspections (reviewed in Section 3.3.1.11 of this SER) includes pressurizer subcomponent inspections to check for leaks. The subcomponents include full- and partial-penetration welds in nozzles, and bolting. In addition, as mentioned by the applicant in response to this action item, ASME Section XI, Examination Category B-P inspection requirements may also be used to check for pressurizer leaks. Since the applicant has identified a broad range of AMPs that will detect pressurizer leakage, the staff finds that the applicant's response to this action item is acceptable.

- Item 8: The staff concludes that an AMP is necessary to control and manage the potential for SCC to occur in welded pressurizer penetration nozzles and manway bolting materials, and recommends that a licensee could credit the following programs as the basis for managing the phenomena of PWSCC/IGSCC of the pressurizer components: (1) the primary coolant chemistry program; (2) the ISI program of the pressurizers; and (3) the plant-specific quality assurance program as it pertains to assuring that previous welding activities on welds in the pressurizer have been controlled in accordance with the pertinent requirements of 10 CFR 50, Appendix B, and with the pertinent welding requirements of the ASME Code for Class 1 systems. The staff concludes that applicants need to extend AMP-2.1 to the pressurizer penetration nozzles, to the nozzle-to-vessel welds, and to the manway bolting materials, and to include the appropriate Code requirements among the program attributes listed in Table 4-1 and summarized in the text in Section 4.1 of this report.

Applicants for license renewal must provide sufficient details in their LRAs as to how their primary coolant chemistry control programs, ISI programs, and 10 CFR 50, Appendix B quality assurance programs will be sufficient to manage the potential for SCC to occur in the pressurizer nozzle components and bolted manway covers during the proposed extended operating term for their facilities.

Response (North Anna): SCC of bolting is addressed in Appendix C. The chemistry control program for primary systems manages SCC in pressurizer subcomponents, including nozzles and the manway cover insert plate, by limiting total halogen content in the primary coolant. ISI program inspections (Table IWB-2500-1) are used to detect cracking resulting from flaw initiation and growth. These programs are described in Appendix B, which include a demonstration of the effectiveness of the programs. The Quality Assurance Program is applicable to all programs credited for aging management.

Response (SPS 1/2): The response to this action item for Surry is similar to that for North Anna except that the following sentence has been added for the Surry response. Based on cracking of instrument line nozzles that has occurred, augmented inspection activities (visual examination) are also performed on small-bore instrument and sample nozzles to check for indications of boric acid.

The staff finds that the applicant has provided sufficient details in its LRAs as to how their primary coolant chemistry control programs, ISI programs, and 10 CFR 50, Appendix B quality assurance programs will be sufficient to manage the potential for SCC, therefore, the staff finds these responses to be acceptable.

- Item 9: Applicants must propose an AMP to verify whether or not thermal fatigue-induced cracking has propagated through the clad into the ferritic base material or weld material beneath the clad.

  Response: There is no industry experience to suggest that cracks initiating at the clad inner surfaces in the pressurizer will propagate into the underlying base metal or weld metal. Observed flaws in other plants were monitored for an extended period of time, and no significant flaw growth was observed. In 1990, several indications were discovered in the pressurizer cladding in the Connecticut Yankee plant. Ultrasonic inspection confirmed that the indications did not penetrate into the ferritic base metal and, therefore, in accordance with ASME Section XI, the indications were acceptable without repair. A surveillance program was initiated, and after two follow-up inspections that showed no change, the surveillance program was discontinued with NRC approval. In several of the cases of observed cracking, fracture mechanics analyses were performed, and demonstrated that the cladding indications would not compromise the integrity of the primary system components.

At temperatures greater than 82°C (180°F), the cladding has virtually no impact on the fracture behavior. This is the low end of the plant operating temperature range. ASME Section XI flaw evaluation rules require that the effects of cladding must be considered in any structural integrity evaluation, especially for postulated flaws that penetrate the cladding into the base metal. The actual impact on the cladding on such an evaluation is negligible. The pressurizer shell design considers fatigue usage throughout the operating lifetime and includes adequate margin. This is expected to preclude the formation of fatigue cracks in the cladding material. The fracture mechanics evaluations performed for actual observed cracks in other plants indicate that the cracks do not grow significantly over the plant lifetime. Therefore, a specific aging management program to manage fatigue cracking of the pressurizer cladding is not required.

On the basis of the prior evaluation for the Connecticut Yankee pressurizer which showed that, after two follow-up inspections, there was no evidence of further crack growth, and that none of the cracks had penetrated into the base metal, the staff concurs that an aging management program for underclad cracking is not required. For the Connecticut Yankee pressurizer, the topical report states that it was concluded that the cracks may have been caused by a spray of cold water onto the cladding during a low-water transient. Therefore, this is a situation not generally applicable to Westinghouse pressurizers. The staff finds this response to be acceptable.

- Item 10: The staff is concerned that 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 extended operating periods if applicants can provide reasonable justification that sensitization has not occurred in these welds during the fabrication of these components. Therefore, applicants for license renewal must provide a discussion of how the implementation of their 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. In addition, the staff request that applicants for license renewal identify whether these welds fall into item B8.20 of Section XI, Examination Category B-H, Integral Attachments for Vessels, and if applicable, whether the applicants have performed the mandatory volumetric or surface examinations of these welds during the ISI intervals referenced in the examination category.

Response: The pressurizer cladding material and weld metal used to join the pressurizer internal supports and cladding were selected to have sufficiently low carbon content to minimize the possibility of sensitization. However, the existence of sensitized areas in the heat-affected zones of 304 stainless steel support welds cannot be totally excluded. Therefore cracking due to stress corrosion cracking is an aging effect requiring aging management for internal pressurizer welds. The chemistry control program for primary systems, as described in Section B2.2.4 of Appendix B, is credited with management of this aging effect. Control of oxygen, chlorides, and halogens provides an essentially benign environment, which has been shown to be effective in limiting stress corrosion cracking. Pressurizer internal welds do not fall under item B8.20 of ASME Section XI Examination Category B-H.

The staff concurs that sensitization may be present in the heat-affected zones of 304 stainless steel support welded to the cladding. It also concurs that the chemistry control program for primary systems will mitigate SCC in these welded joints. Finally, the staff agrees that internal welds do not fall under item B8.20 of examination category B-H since footnote (1)a in Table IWB-2500-1 (Examination Category B-H) states that this examination pertains to attachments on the outside surface of the pressure retaining component. Therefore, the staff finds this to be acceptable.

3.4.4.2.1 Aging Effects

The materials of construction for the pressurizer are stainless steel, low-alloy steel, and carbon steel. In Section 3.1.4 of the North Anna LRA it is stated that the pressurizer surge, spray, relief, and safety nozzles are all buttered with nickel-based alloy (Alloy 82/182). For Surry it is stated that all surfaces of low-alloy and carbon steel subcomponents that are in contact with borated water are weld overlaid with stainless steel to provide corrosion resistance. From Table 3.1.4-1 of the LRAs, the aging effects requiring management are:

- cracking
- loss of material
- loss of pre-load

Cracking of carbon and low-alloy steel pressurizer subcomponents may occur in air and in treated water steam environments. In Section 4.3.4 of the LRA, the applicant noted that the surge line nozzle in the pressurizer is the leading indicator for reactor water environmental fatigue effects, specifically, the surge line connecting the pressurizer to the reactor coolant hot leg piping. An augmented inspection program has been proposed as a follow-up action to examine the surge line weld at the hot leg piping connection in order to detect flaw initiation and growth. The support skirt and flange, lower head, the relief nozzle, the safety nozzle, the shell, spray nozzle, surge nozzle, and seismic support lugs are all susceptible to fatigue cracking in an air environment, as stated in Table 3.1.4-1. Stainless steel and nickel-based subcomponents, mainly nozzles and thermal sleeves, are susceptible to SCC in the presence of treated water and steam, also stated in Table 3.1.4-1.

Leakage of primary coolant in the pressurizer will lead to evaporation and concentration of the coolant and may cause significant loss of material (wastage) of carbon and low-ploy steel subcomponents. Table 3.1.4-1 of the LRA lists 12 pressurizer subcomponents that may be affected by loss of materials. This aging effect is managed by the boric acid corrosion surveillance AMP which the staff has reviewed in Section 3.3.1.3 of this SER.

Loss of pre-load is possible in the manway cover bolts of the pressurizer. This may be a result of corrosion of the bolt by boric acid or by stress relaxation within the bolt caused by thermally activated structural changes in the steel. This aging effect is managed by the ISI program - component and component support AMP which the staff has reviewed in 3.3.1.11 of the SER.

Based on these considerations, the staff finds the aging effects identified by the applicant for the pressurizer components to be consistent with the topical report.

3.4.4.2.2 Aging Management Programs

The staff's evaluation of the applicant's AMPs focused on the program elements rather than details of specific plant procedures. The staff's approach to evaluating each program and activity used to manage the applicable aging effects is described in Section 3.3 of this SER. Table 3.1.4-1 of the LRA lists the pressurizer subcomponents that require aging management together with their intended functions, applicable aging effects, and the AMPs designed to manage the aging effects. The applicant specifies in Table 3.1.4-1 that the following AMPs as being applicable to the pressurizer:

- chemistry control program for primary systems
- ISI program - components and component support inspections
- boric acid corrosion surveillance

The chemistry control program for primary systems is described in Section B2.2.4 of the LRAs. Its purpose is to provide reasonable assurance that water quality is compatible with the materials of construction in plant systems and equipment in order to minimize loss of material and cracking. This AMP is based on the applicant's Technical Specifications and Electric Power Research Institute (EPRI) guidelines provided in technical report TR-105714, "Primary Water Chemistry Guidelines." Pressurizer materials included in this AMP include stainless steels susceptible to cracking and loss of material in treated water environments, and North Anna nickel-based 82/182 alloys in treated water environments. The coolant chemistry is monitored and trended so that timely indication of abnormal chemistry conditions is possible. Corrective action is taken if abnormal trends are detected so that water chemistry is maintained within acceptable limits. A staff review of the chemistry control for primary systems AMP is given in Section 3.3.1.4 of this SER.

The ISI program - component and component support inspections AMP is described in Section B2.2.11 of the LRAs. Its purpose is to inspect ASME Class 1 and 2 components to provide reasonable assurance that components and component supports are in compliance with the provisions of ASME Section XI, Subsections IWB, IWC, and IWF. From the LRA, the inspections applicable to the pressurizer include the following Class 1 subcomponents:

- Examination Category B-B (pressure-retaining welds in vessels other than reactor vessel - volumetric)
- Examination Category B-D (full-penetration welds of nozzles in vessels - volumetric)
- Examination Category B-E (pressure-retaining partial penetrations in welds in vessels - visual)
- Examination Category B-F (pressure-retaining dissimilar metal welds - volumetric/surface)
- Examination Category B-G-1 (pressure-retaining bolting greater than 2 inches in diameter - visual/surface/volumetric)
- Examination Category B-G-2 (pressure-retaining bolting less than 2 inches in diameter - visual)
- Examination Category B-H (integral attachment for vessels)
- Examination Category B-P (all pressure-retaining components)

The ISI examinations are carried out to detect component degradation prior to loss of intended function. The inspections are capable of detecting loss of material, cracking, gross indications of loss of pre-load, and gross loss of fracture toughness which may manifest itself as cracking. A staff review of this AMP is given in Section 3.3.1.11 of this SER.

The boric acid surveillance AMP is described in Section B2.2.3 of the LRA. It is relevant to carbon and low-alloy steel subcomponents of the pressurizer as described in Table 3.1.4-1 of the application. Subcomponents such as the shell, lower head, manway and manway bolts, relief nozzle, and safety nozzle are parts of the pressurizer that may be involved as a result of leaking primary coolant and its concentration to form boric acid. Loss of material is the aging effect monitored using inspections that comply with NRC Generic Letter 88-05 and ASME Section XI criteria. Visual inspections are performed to detect evidence of coolant leakage or boric acid residue. If degradation of susceptible components has occurred, an engineering evaluation is made to determine whether the observed condition is acceptable without repair. For degradation that is adverse to quality, the occurrence is entered into the plant corrective action system. A staff review of this AMP is given in Section 3.3.1.3 of this SER.

On the basis of the evaluations of these AMPs identified above, the staff concludes that these AMPs are acceptable for managing the pertinent aging effects and providing assurance that the intended functions of the pressurizer components will be maintained consistent with the CLB throughout the period of extended operation.

Fatigue cracking of pressurizer subcomponents is evaluated as a TLAA on metal fatigue in Section 4.3 of the LRA. The analyses for the pressurizer include ASME Code, Section III, Class 1 evaluations of the CUF for subcomponents, and environmentally-assisted fatigue effects. A staff review of this TLAA is given in Section 4.3 of this SER.

3.4.4.3 Conclusions

The staff has reviewed the information included in Section 3.1.4 of the LRAs, as supplemented by the RAI responses. On the basis of this review, the staff concludes that the applicant has demonstrated that the effects of aging associated with the pressurizer components will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB throughout the period of extended operation.

3.4.5 Steam Generators

Each unit has three recirculating steam generators, with one steam generator in each of the three reactor coolant loops. They are vertical, shell and U-tube heat exchangers with integral moisture-separating equipment. The steam generators facilitate transfer of heat from the single-phase, high-pressure, high-temperature borated reactor coolant on the primary side of the tubes to the two-phase steam-water mixture on the secondary side. Reactor coolant flows through the primary side of the inverted U-tubes, entering and leaving through he primary nozzles located in the hemispherical bottom chamber (the channel head). The channel head is welded to the tubesheet from which the tubes bundle is attached. Within the channel head is a vertical divider plate which separates the inlet from the outlet flow. The tube bundle is surrounded by a cylindrical wrapper. The space between the wrapper and steam generator shell is termed as the downcomer. Feedwater and recirculated water flows down the downcomer, around the base of the wrapper, and through the tube bundle. The feedwater is heated to boiling in the tube bundle by the transfer of heat from the reactor coolant on the primary side. Saturated steam/water mixture enters the moisture separator section where the water is removed from the mixture and dried in the evaporator. Dry steam exits the steam outlet-nozzle and is piped to the turbines.

3.4.5.1 Summary of Technical Information in the Application

The steam generators are designed and fabricated in accordance with Section III of the ASME Boiler and Pressure Vessel Code requirements. Table 3.1.5-1 of the application provides the following information on each steam generator subcomponent: (1) the passive function, (2) the material group, (3) the environment, (4) the aging effects requiring management, and (5) the specific aging management activities that would manage these aging effects during the extended period of operation. The subcomponents requiring management include: anti-vibration bars, channel head, channel head divider plate, feedwater inlet nozzle, primary inlet and outlet nozzle safe ends, primary inlet and outlet nozzles, primary manway (includes pad and cladding), primary manway cover and insert, primary manway cover bolting, secondary closure bolting, secondary closure covers, secondary manway (includes pad), secondary side shell penetrations, secondary side shell, stay rod, steam flow limiter, steam outlet nozzle, support pads, tube bundle wrapper, tube plugs, tube support plates, tubesheet and cladding, and the U-tubes. These subcomponents are periodically inspected in accordance with ASME Section XI, Subsections IWB and IWC requirements and the plant TS. Primary system piping connected to the steam generators is addressed in Sections 3.1.1 of the LRAs, whereas secondary system piping attached to the steam generator is addressed in Section 3.4 of the LRAs.

OF the steam generator subcomponents that are considered within the scope of the license renewal, all have the passive function of providing a pressure boundary with the following exceptions. The anti-vibration bars, the stay rod, support pads, tube bundle wrapper, and tube support plates have the intended function of providing structural and/or functional support for in-scope equipment; the channel head divider plate has the intended function of providing flow distribution; and the steam flow limiter has the intended function of restricting steam flow in the event of a main steam line break.

3.4.5.1.1 Aging Effects

The materials of construction for the steam generators that are subject to aging management review are in the carbon steel/low-alloy steel material group and include the channel head, secondary side shell, stay rod, nozzles, manways, tubesheet, tube bundle wrapper, support pads, and bolting. All surfaces exposed to borated primary coolant are clad with stainless steel or nickel-based alloys. Stainless steel subcomponents include the anti-vibration bars, primary inlet and outlet nozzle safe ends, and tube support plates. Nickel-based alloy components include the channel head divider plate, steam flow limiter, steam generator tubes, and tube plugs. The primary-side subcomponents are exposed to borated (primary) water conditions, the secondary-side subcomponents to a mixture of treated (secondary) water and steam, and the external surfaces of the steam generator are exposed to air, and possibly borated water leakage conditions.

In Section 3.1.5 of the LRAs, the applicant listed the following aging effects that will require management:

- cracking of carbon steel, low-alloy steel, stainless steel, and nickel-based alloy subcomponents in treated water, steam, or air environments
- loss of material from carbon steel, low-alloy steel, stainless steel, and nickel-based alloy subcomponents in treated water or steam environments
- loss of material from low-alloy steel subcomponents in a borated leakage environment
- loss of pre-load of ASME Class 1 low-alloy steel bolting in an air environment

3.4.5.1.2 Aging Management Programs

The applicant specifies the following AMPs as being applicable to the steam generators:

- chemistry control program for primary systems
- chemistry control program for secondary systems
- boric acid corrosion surveillance
- steam generator inspections

The applicant concluded that these AMPs will ensure that aging effects associated with the steam generator subcomponents will be managed so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation. Table 3.1.5-1 of the LRA lists the steam generator subcomponents that require aging management together with their intended functions, applicable aging effects, and the AMPs designed to manage these aging effects.

Fatigue cracking of steam generator subcomponents is evaluated as a TLAA on metal fatigue in Section 4.3 of the LRAs. The analyses for the steam generator include ASME Code, Section III, Class 1 evaluations of the CUF for subcomponents. A staff review of this TLAA is given in Section 4.3 of this SER.

3.4.5.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3) and (c)(1), the staff reviewed the information included in Section 3.1.5 (Table 3.1.5-1) as supplemented by RAI responses by the applicant, and pertinent sections of LRA Appendices A and B, regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended functions of subcomponents in the steam generators will be maintained consistent with the CLB under all design loading conditions during the period of extended operation.

Both North Anna and Surry have long operating experience; Surry has been operating since 1972/1973 and North Anna since 1978/1980. Originally, all of them were designed with Westinghouse model 51 recirculating, feed ring type steam generators. These steam generators had carbon steel tube support plates with drilled round holes. During the seventies, all steam generators had experienced significant degradation of their steam generator tubes, tube support plates and other internal components, and had undergone an extensive repair program. In accordance with Section 2.3.1.5 of the LRAs, this repair program consisted of refurbishment of the upper assembly in addition to replacement of the lower assembly (including the channel head, U-tubes, tubesheet, and lower shell section). During 1980-1981, Surry replaced the lower section of their steam generators with Westinghouse model 51F components and during 1993-1995, North Anna replaced the lower section of their steam generators with Westinghouse model 54F components. Both replacement Westinghouse models 51F and 54F have stainless steel and trefoil or quatrefoil broached-type tube support plates, which are resistant to the erosion-corrosion and cracking that were experienced in model 51 steam generators. These enhanced models use hydraulically expanded, thermally treated Alloy 600 tubing and 405 stainless steel tube support plates.

In response to the NRC Generic Letter 97-06, the Westinghouse owners group conducted a survey on the degradation susceptibility of steam generator internal components. In accordance with the plant responses delineated in WCAP-15031, several components within the steam generator internals of the two replacement Westinghouse models (i.e., 51F and 54F) were observed to have some degradation, while several other components were determined to have low susceptibility to some other degradation. Erosion-corrosion in moisture separators, and feed ring/J-tubes, and cracking in the transition cone girth welds were observed in some steam generators. Also, the survey determined that there exists low susceptibility to cracking of tube support plate ligaments and wrapper near its supports (and hence wrapper drop). The licensees have adopted appropriate inspection and maintenance activities to address these known degradations in steam generator internals. There are no near-term changes in the steam generator inspection program that are thought to be necessary at this time. However, for a long-term solution to these age-related degradation the licensee intends to implement, as appropriate, the recommended inspection activities given in WCAP-15031 and WCAP-15104.

With regard to maintaining the pressure boundary of steam generator tubes, the applicant stated that less than 1% of the total number of tubes are plugged at Surry and only one tube was plugged at each North Anna unit since their steam generator replacements.

3.4.5.2.1 Aging Effects

The aging effects identified by the applicant in Table 3.1.5-1 of the LRAs as being applicable to the steam generators include the following:

- cracking
- loss of material
- loss of pre-load (applicable to ASME Class 1 subcomponents only)

The applicant stated in Section 3.1.5 of the LRAs that cracking due to fatigue is evaluated for the steam generator as a TLAA. Also, in Section 4.3 of the LRA, the applicant states that steam generator components have been analyzed using the methodology of the ASME B&PV Code, Section III, Class 1. The steam generator components within the scope of license renewal belong to both ASME Class 1 and 2 classification. In response to RAI Item 3.1.5.2.1-1(a), the applicant stated that both Class 1 and Class 2 components were evaluated for fatigue using the methodology for Class 1 components. The 40-year CUFs bound the periods of extended operation since the number of design cycles assumed for 40-years is bounding for 60-years of operation.

In Table 3.1.5-1 of the LRA, each steam generator component within the scope of license renewal is subject to the loss of material due to crevice corrosion, pitting, and general corrosion requiring aging management. The tube support plates are not subject to flow-accelerated corrosion since they are fabricated of stainless steel.

Based on these considerations, the staff finds the aging effects identified by the applicant for the steam generator components to be consistent with industry experience, therefore, the staff finds this to be acceptable.

3.4.5.2.2 Aging Management Programs

The staff's evaluation of the applicant's AMPs focused on the program elements rather than details of specific plant procedures. The staff's evaluation of each program and/or activity used to manage the applicable aging effects is described in Section 3.3 of this SER.

The AMPs being used by the applicant to manage the aging effects associated with the steam generators are listed in the application as:

- chemistry control program for primary systems
- chemistry control program for secondary systems
- boric acid corrosion surveillance
- steam generator inspections

The chemistry control program for primary systems is described in Section B2.2.4 of the LRAs. Its purpose is to provide reasonable assurance that water quality is compatible with the materials of construction in plant systems and equipment in order to minimize loss of material and cracking. This AMP is based on the applicant's technical specifications and Electric Power Research Institute (EPRI) guidelines provided in technical report TR-105714, "Primary Water Chemistry Guidelines." Steam generator materials included in this AMP include stainless steels susceptible to cracking and loss of material in treated water environments, and North Anna nickel-based 82/182 alloys in treated water environments. The coolant chemistry is monitored and trended so that timely indication of abnormal chemistry conditions is possible. Corrective action is taken if abnormal trends are detected so that water chemistry is maintained within acceptable limits. A staff review of the chemistry control for primary systems AMP is given in Section 3.3.1.4 of this SER.

The chemistry control program for secondary systems is described in Section B2.2.5 of the LRAs. Its purpose is to provide reasonable assurance that water quality is compatible with the materials of construction in the plant systems and equipment in order to minimize loss of material and cracking. This program is stated by the applicant to provide an environment that minimizes material degradation, maintains material integrity, and reduces the amount of corrosion product that could interfere with equipment operation and heat transfer. This AMP is based on EPRI guidelines provided in technical report TR-102134, "PWR Secondary Water Chemistry Guidelines". These guidelines reflect industry operating experience to optimize plant chemistry control. The applicant's chemistry control program is revised to maintain consistency with the EPRI guidelines. A staff review of the chemistry control for secondary systems AMP is given in Section 3.3.1.5 of this SER.

The boric acid corrosion surveillance AMP is described in Section B2.2.3 of the LRAs. It is relevant to carbon and low-alloy steel subcomponents of the steam generator as described in Table 3.1.5-1 of the application. Subcomponents that are managed by this AMP include the channel head, feedwater inlet nozzle, primary inlet and outlet nozzles, primary manway (including pad and cladding), primary manway cover and insert, primary manway cover bolting, secondary closure cover bolting, secondary closure covers, secondary manway, secondary side shell penetrations, secondary side shell, steam outlet nozzle, and support pads. The aging effect to be detected is loss of material from susceptible components due to leakage from borated water systems. Inspection of these systems is performed in compliance with the requirements of NRC Generic Letter 88-05 and ASME Section XI. A staff review of the boric acid corrosion surveillance AMP is given in Section 3.3.1.3 of this SER.

The steam generator inspections AMP is described in Section B2.2.18 of the LRAs. The applicant stated that this AMP is carried out in accordance with the individual ISI programs for each of the four units . In accordance with 10 CFR 50.55a, the inspections are implemented to meet the requirements of Subsections IWB and IWC of ASME Section XI. Primary side inspections are focused on the following areas:

- general inspection of the full length of the tubes
- special interest inspections of suspected anomalous indications in accordance with site-specific guidelines
- U-bend areas of anti-vibration bar contact points
- critical area inspections at the U-bend transition of Row 1 tubes
- critical area inspections of the hot leg top-of-tubesheet expansion area
- video inspections for general condition assessment of the tubesheet and tubesheet plugs
- weld inspections
- bolting

Secondary side inspections are focused on:

- inner radii inspections of feedwater and main steam nozzles
- weld inspections
- supports
- routine video inspections of the tubesheet area and the annulus area, as necessary, to detect the presence of deposits, sludge, foreign material, or other general degradation

The secondary side inspections exclude the wrappers, tube support plates, and transition cone girth welds as suggested by the owners group in its responses to GL 97-06. A staff review of this AMP is given in Section 3.3.1.18 of this SER.

In addition to the above-mentioned AMPs, the applicant listed in Section B2.2.1 of the LRAs two augmented inspection activities for the steam generator that are performed in addition to ASME Section XI ISIs. These are VT-1 inspections of the steam generator supports every 40 months for North Anna, and UT or supplemental RT of the feedwater nozzles every refueling outage for both plants.

On the basis of the evaluations of the AMPs identified above, the staff concludes that these AMPs are acceptable for managing the pertinent aging effects and providing assurance that the intended functions of the steam generator components will be maintained consistent with the CLB throughout the period of extended operation.

3.4.5.3 Conclusions

The staff has reviewed the information included in Section 3.1.5 of the LRAs, as supplemented by the RAI responses. On the basis of this review, the staff concludes that the applicant has demonstrated that the effects of aging associated with the steam generator components will be managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB throughout the period of extended operation.

3.5 Aging Management of Engineered Safety Features

In the North Anna and Surry LRAs, Section 2.3.2, "Engineered Safeguards Scoping and Screening," the applicant describes the results of the scoping and screening of the engineered safety features (ESFs) SSCs that are within the scope of license renewal and the ESF SCs that are subject to an AMR. The applicant describes its AMR for the ESF SCs in Section 3.2, "Aging Management of Engineered Safety Features Systems" of each LRA. The various AMPs used to manage the aging of the ESF SCs are described in each LRA, Appendix B, as applicable.

The NRC staff review of the scoping and screening results for NAS 1/2 and SPS 1/2 ESFs systems are described in Section 2.3.2 of this SER. The staff's review of the applicant's AMR activities for the NAS 1/2 and SPS 1/2 ESFs are the subject of this section of the SER. This review is being performed to determine whether the applicant has demonstrated that the effects of aging for the SCs of the ESFs that are subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation in accordance with 10 CFR 54.21(a)(3).

3.5.1 Summary of Technical Information in the Application

In the North Anna and Surry LRAs, Section 2.3.2, "Engineered Safeguards Scoping and Screening," the applicant identified five systems that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4. The five systems include the quench spray (QS)/containment spray (CS) systems, fuel pit cooling (FC), recirculation spray (RS), residual heat removal (RH), and safety injection (SI) systems. A brief description of the systems is provided in the LRA and is given below.

3.5.1.1 Systems Descriptions

Quench Spray/Containment Spray Systems

Each Unit of the NAS has a quench spray (QS) system. The SPS 1/2 each has an equivalent system referred to as the containment spray (CS) systems. These systems are identical for the purpose of an AMR for license renewal. In North Anna LRA, Section 2.3.2.1, "Quench Spray," and the Surry LRA, Section 2.3.2.1, "Containment Spray," the applicant describes the SCs of the QS/CS systems that are within the scope of license renewal and subject to an AMR for both NAS and SPS. The QS/CS systems are designed to pump cool, borated water from the refueling water storage tank (RWST), mixed with a sodium hydroxide solution from the chemical addition tank (CAT), through spray ring headers and nozzles into the Containment. The spray solution absorbs heat from the Containment atmosphere to reduce pressure and prevent challenging the structural integrity of the Containment. In addition, the spray reduces the airborne iodine concentration in the post-LOCA Containment atmosphere to maintain accident-dose within limits. The RWST also provides the source of water to the safety injection (SI) system for the injection phase of design basis accident mitigation. Therefore, the major flowpaths of the QS/CS systems are within the scope of license renewal and subject to an AMR. The QS/CS SCs that require an AMR are listed in Tables 3.2-1 of each LRA.

Fuel Pit Cooling System

In the North Anna and Surry LRAs, Section 2.3.2.2, "Fuel Pit Cooling," the applicant describes the SCs of the NAS 1/2 and SPS 1/2 fuel pit cooling (FC) systems that are within the scope of license renewal and subject to an AMR. The NAS 1/2 and SPS 1/2 FC systems are identical for the purpose of an AMR for license renewal and there are no notable differences. At both North Anna and Surry, the FC systems transfer heat from spent fuel pools to component cooling (CC) system. The NAS and SPS FC systems also provide a means for water chemistry control for the spent fuel pools. The FC systems are used to circulate borated water from the spent fuel pools through the FC heat exchangers and back to the pools. The FC systems pump suction connects to the spent fuel pools at an elevation that would prevent the pools from draining below the limiting water level in the event of a leak in the FC systems. A bypass purification loop associated with each FC system provides the capability to filter and demineralize the spent fuel pool water. The portions of the FC system that are subject to an AMR consist primarily of the SCs that support the capability to remove heat from the spent fuel pool. The FC SCs that require an AMR are listed in Tables 3.2-2 of each LRA.

Recirculation Spray System

In the North Anna and Surry LRAs, Section 2.3.2.3, "Recirculation Spray," the applicant describes the components of the NAS 1/2 and SPS 1/2 recirculation spray (RS) systems that are within the scope of license renewal and subject to an AMR. The NAS 1/2 and SPS 1/2 RS systems are similar.

The RS systems are designed to provide long-term heat removal from the Containment atmosphere and core cooling water following a design basis loss-of-coolant accident (LOCA). The RS system transfers heat from the reactor core, via coolant spilled from the break, and from the containment atmosphere to the service water (SW) system through the RS heat exchangers. Water collected in the containment sump is pumped through the heat exchangers, then through spray ring headers and nozzles, into the Containment atmosphere. The RS system is designed to return the post-LOCA Containment to sub-atmospheric pressure and to maintain sub-atmospheric conditions for the duration of the accident recovery, thus preventing out-leakage of fission products. The cooled water in the Containment sump is pumped back through the reactor core by the SI system.

For the NAS 1/2, the RS casing cooling components also provide a source of cool borated water to the suction of the RS pumps located outside of containment. This ensures that the NAS RS pumps will have adequate net positive suction head (NPSH) when called upon for service. The SPS 1/2 RS systems do not perform this function.

The major flowpaths of the RS systems are within the scope of license renewal and subject to an AMR. The RS SCs that require an AMR are listed in Tables 3.2-3 of each LRA.

Residual Heat Removal System

In the North Anna and Surry LRAs, Section 2.3.2.4, "Residual Heat Removal," the applicant describes the components of the NAS 1/2 and SPS 1/2 residual heat removal (RH) systems that are within the scope of license renewal and subject to an AMR. The NAS 1/2 and SPS 1/2 RH systems are identical for the purpose of an AMR for license renewal and there are no notable differences. The primary function of the RH systems is to transfer heat from the RCSs to the component cooling (CC) systems during reactor shutdown conditions. Water is drawn from the RCSs, pumped through the RH heat exchangers, and returned to the RCSs to control primary system temperatures. The NAS 1/2 and SPS 1/2 RH systems are in service only when RCS temperatures and pressures have been reduced to 350°F and 450 psig, respectively. In addition, the RH systems provide the capability to pump the reactor cavity water back to the refueling water storage tank following refueling operations. The RH systems also are relied upon in the 10 CFR Part 50, Appendix R Fire Protection design basis for heat removal to reach cold shutdown conditions. Portions of RH system piping and certain valves are within the ASME Class 1 reactor coolant system pressure boundary. The major flowpaths of the RH systems are within the scope of license renewal and subject to an AMR. The RH SCs that require an AMR are listed in Tables 3.2-4 of each LRA.

Safety Injection (SI) System

In the North Anna and Surry LRAs, Section 2.3.2.5, "Safety Injection," the applicant describes the components of the NAS 1/2 and SPS 1/2 safety injection (SI) systems that are within the scope of license renewal and subject to an AMR. The NAS 1/2 and SPS 1/2 SI systems are identical for the purpose of an AMR for license renewal and there are no notable differences. The functions of the SI systems are to provide emergency cooling to the reactor core and to provide an adequate shutdown margin in the event of a loss-of-coolant accident (LOCA). The SI systems include high-head injection pumps, low-head injection pumps, and hydro-pneumatic accumulator tanks that provide injection of borated water into the reactor coolant system. The pumps also provide the capability to remove reactor core decay heat for extended periods following an accident. This is accomplished by recirculating coolant, as cooled by the RS system, from the containment sump through the core.

The high-head SI pumps provide a dual function as charging pumps as described in Section 2.3.3.1, Chemical and Volume Control (CH), of the applications, and are evaluated for the effects of aging with the CH system components (see Section 3.3.1, "Primary Process Systems" of each LRA). Portions of SI system piping and certain SI valves are within the ASME Class 1 reactor coolant system pressure boundary.

The major flowpaths of the SI systems are within the scope of license renewal and subject to an AMR. The SI SCs that require an AMR are listed in Tables 3.2-5 of each LRA.

3.5.1.2 Aging Effects

In both North Anna and Surry LRAs, Section 3.2, the applicant provides a summary of the results of the AMR for the SCs of the ESF systems. The AMR results are listed in each LRA on Tables 3.2-1 through 3.2-5. The tables provide the following information related to each component commodity group: (1) the "passive functions", (2) the material group, (3) the environment, (4) the aging effects requiring management, and (5) the specific activities that manage the identified aging effects.

Materials

The materials of construction for the ESF components that are subject to AMR include brass, carbon steel, low-alloy steel, stainless steel, and titanium. Copper alloys and nickel-based alloy materials are also used.

Environments

In the North Anna and Surry LRAs, Table 3.0-1, "Internal Service Environment," and Table 3.0-2, "External Service Environment," the applicant states that the ESF components, subjected to an AMR, are exposed to the following environments; air, atmosphere/weather, borated water leakage, gas, raw water, soil, and treated-water.

In both North Anna and Surry LRAs, Section 3.2, the applicant states the following four aging effects that need to be managed for the ESF SCs for the periods of extended operations:

- cracking
- loss of material
- loss of pre-load (applicable to Class 1 bolting exposed to an air environment)
- reduction in fracture toughness (applicable to cast austenitic stainless steel [CASS] components in a high-temperature treated-water environment)

The applicant uses Tables 3.2-1, 3.2-2, 3.2-3, 3.2-4, and 3.2-5 to identify which of these aging effects will specifically need to be managed for each of the material of fabrication and environmental condition combinations that apply to the ESF component commodity groups that are subject to an AMR.

Applicable Aging Effects

In the North Anna and Surry LRAs, Section 3.2, the applicant states that it has reviewed site-specific operating experience, and industry-wide experience to support its determination of applicable aging effects for the ESF systems. The applicant identified the following applicable aging effects associated with the materials and environments described above for the ESF components that are within the scope of license renewal and subject to an AMR:

- in the North Anna and Surry LRAs, Tables 3.2-1, the applicant identified the following four applicable aging effects for the material and environmental conditions that exist for NAS 1/2 and SPS 1/2 QS/CS components: loss of material, cracking, loss of preload, or reduction of fracture toughness
- in the North Anna and Surry LRAs, Tables 3.2-2, the applicant identified the following four applicable aging effects for the material and environmental conditions that exist for NAS 1/2 and SPS 1/2 FC components: loss of material, cracking, loss of preload, or reduction of fracture toughness
- in the North Anna and Surry LRAs, Tables 3.2-3, the applicant identified the following four applicable aging effects for the material and environmental conditions that exist for NAS 1/2 and SPS 1/2 RS components: loss of material, cracking, loss of preload, or reduction of fracture toughness
- in the North Anna and Surry LRAs, Tables 3.2-4, the applicant identified the following four applicable aging effects for the material and environmental conditions that exist for

NAS 1/2 and SPS 1/2 RH components: loss of material, cracking, loss of preload, or reduction of fracture toughness

- in the North Anna and Surry LRAs, Tables 3.2-5, the applicant identified the following four applicable aging effects for the material and environmental conditions that exist for NAS 1/2 and SPS 1/2 SI components: loss of material, cracking, loss of preload, or reduction of fracture toughness

3.5.1.3 Aging Management Programs

In both the North Anna and Surry LRAs, Section 3.2, the applicant identified the following programs that will be used to manage the applicable aging effects for the ESF SCs that are within the scope of license renewal and subject to an AMR. The materials, environments, aging effects and AMPs are listed in Tables 3.2-1, 3.2-2, 3.2-3, 3.2-4, and 3.2-5 of each LRA for the QS, FC, RS, RH, and SI system components, respectively).

- boric acid corrosion surveillance program (refer to each LRA Section B2.2.3)
- buried piping and valve inspection activities (refer to each LRA Section B2.1.1)
- chemistry control program for primary systems (refer to each LRA Section B2.2.4)
- general-condition-monitoring activities (refer to each LRA Section B2.2.9)
- infrequently accessed area inspection activities (refer to each LRA Section B2.1.2)
- ISI program - component and component support inspections (refer to each LRA Section B2.2.11)
- tank inspection activities (refer to each LRA Section B2.1.3)
- work control process (refer to each LRA Section B2.2.19)

For SPS 1/2, the applicant also credits the augmented inspection activities (Section B2.2.1 of the LRA) to manage cracking of those SPS ESF components that are fabricated from sensitized stainless steel materials. These sensitized stainless steel materials are not used at NAS 1/2 and, therefore, the additional augmented inspection activities are not used at NAS 1/2.

3.5.2 Staff Evaluation

The staff has reviewed the information in the North Anna and Surry LRAs, Sections 2.3.2, and 3.2, and the portions of Appendix B that apply to the ESF systems to determine whether the applicant has demonstrated compliance with the requirements of 10 CFR 54.21(a)(3). In addition, the staff reviewed the applicable portions of the North Anna and Surry UFSARs, plant and industry (as applicable) operating history, the license renewal system drawings provided with each LRA, and other applicable portions of Appendix A, Appendix B, and Appendix C of each LRA. The staff also had a telecommunication with the applicant on August 9, 2001, to discuss the information provided to, and reviewed by the staff. The clarifications and supplemental information provided by the applicant during the telecommunication is documented and docketed in a letter to the applicant dated October 11, 2001. No request for additional information was needed for the staff to complete its review of the ESF systems.

The staff's review and evaluation of the specific scope of ESF SCs included by the applicant as being within the scope of license renewal and subject to an AMR are provided in Section 2.3.4 of this SER. In addition, the staff's review and evaluation of the different aging management activities credited by the applicant to manage the applicable aging effects of the ESF systems are provided in Section 3.3 of this SER. The staff's review and evaluation of the applicant's AMR for the ESF systems are provided in this section of the SER.

3.5.2.1 Aging Effects

All of the ESF components (i.e., the QS, FC, RS, RH and SI components within the scope of license renewal and subject to an AMR as identified in Tables 3.2-1, 3.2-2, 3.2-3, 3.2-4, and 3.2-5, respectively) are fabricated from austenitic stainless steel materials (including cast austenitic stainless steel [CASS]) with the following exceptions:

- ESF bolting is fabricated from carbon or low alloy steel
- spray nozzles are fabricated from brass (only at NAS)
- residual heat removal system pump seal cooler shells are fabricated from carbon or low-alloy steel

For SPS 1/2, the SPS pump seal cooler tubes are fabricated from copper-nickel alloy in lieu of stainless steel, and the SPS recirculation spray cooler channel heads, and tubes are fabricated from titanium in lieu of stainless steel. In addition, for some of the SPS QS and RH piping, the applicant differentiates if the stainless steel material used to fabricate the piping was procured in a sensitized condition.

The applicant has identified that the following aging effects are applicable to the ESF components within the scope of license renewal:

- loss of material in carbon or low-alloy steel components exposed to borated water leakage environments or treated-water environments
- loss of material or loss of material and cracking in non-CASS stainless steel components exposed to treated-water environments (As discussed in Appendix C, Section C3.2.1 and C3.2.2 of each LRA, the piping in question is maintained below 140°F to eliminate stress corrosion cracking as a concern. The piping in question is outside of the ASME Class 1 boundary such that flaw initiation and growth is not a concern)
- loss of material in stainless steel components exposed to raw water, intermittent wet/dry air, or atmosphere/weather environments
- loss of material, cracking, and reduction of fracture toughness in CASS valve bodies

The applicable aging effects identified by the applicant are consistent with current industry practices and industry operating experiences and are acceptable to the staff.

For SPS 1/2 RS systems, the applicant identified loss of material as an applicable aging effect for the copper-nickel alloy RS pump sealer tubes when exposed to borated water leakage or treated-water environments. The applicant has conservatively identified that both loss of material and cracking are applicable aging effect for those portions of the SPS ESF piping that are fabricated from stainless steel in the sensitized condition and exposed to treated-water. Identifying loss of material and cracking as applicable aging effects for the material and environment combinations in question are conservative with respect to standard industry practices and are acceptable to the staff.

The applicant has not identified any aging effects associated with titanium, brass, stainless steel, or carbon/low-alloy steel components in a dry air environment. On the basis of current industry knowledge and industry operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. Therefore, the staff did not identify any concerns with the applicant's conclusions that there are no applicable aging effects for metal in a dry air environment.

On the bases of the AMR methodology, the applicant identified the aging effects discussed above. In the North Anna and Surry LRAs, Tables 3.2-1 through, 3.2-5, the applicant listed the applicable aging effects associated with the different components, component functions, materials, and environments, and the applicable aging management activities. In the North Anna and Surry LRAs, Appendix C, the applicant also describes its plant-specific, and its industry-wide operating experience review to support the applicable aging effects identified for the ESF systems. The staff reviewed and verified that the material, environmental, and aging effect combinations are consistent with published literature and industry operating experience, and that there is reasonable assurance that all applicable aging effects have been identified.

In RAI 2.1-3, the staff addressed the Seismic II/I emerging safety issue as it pertains the Surry/North Anna LRA. In this RAI, the staff asked the applicant to identify those non-safety-related (NSR) systems whose spatial orientation and failure could effect the structural integrity and safety functions of safety-related (SR) systems within the scope of license renewal. The applicant's response to RAI 2.1-3, dated February 1, 2002, has increased the license renewal boundary for four of the ESF systems within the scope of license renewal: (1) QS/CS, (2) RH, (3) FC, and (4) SI. In the response to RAI 2.1-3, the applicant provided the AMRs for the expanded portions of the QS/CS, RH, FC, and SI systems brought within the scope of license renewal as part of the applicant's efforts to resolve the Seismic II/I issue for the Surry/North Anna LRA. The applicant has identified that the following aging affects are applicable for the expanded portions of the QS/CS, RH, FC, and SI systems brought within the scope of license renewal:

- loss of material and cracking in stainless steel components exposed to treated water at temperatures above 140°F
- loss of material in stainless steel components exposed to treated water at temperatures at or below 140°F
- loss of material from the external surfaces of stainless steel components exposed to air

The applicant's identification of the materials of fabrication, internal and external environments, and aging effects identified for the expanded portions of the QS/CS, FC, RH, and SI systems brought within the scope of license renewal are consistent with the applicant's identification of aging effects for components with corresponding materials of fabrication/environmental condition combinations originally identified by the applicant in Tables 3.2-1, 3.2-2, 3.2-4, and 3.2-5 of the application, respectively. The applicant's identification of aging effects for these fabrication/environmental condition combinations have been evaluated and found to be acceptable by the staff, as discussed previously in this section.

3.5.2.2 Aging Management Programs

The applicant has identified 8 AMAs for managing the applicable aging effects of the ESF SCs. In each LRA, Tables 3.2-1 through 3.2-5, the applicant identified each of the following AMA and its applications to the SCs and the associated aging effects:

- boric acid corrosion surveillance program to manage loss of material in carbon steel components exposed to borated water leakage for ESF components subject to aging management inside Containment
- general-condition-monitoring activities to manage loss of material in carbon steel components exposed to borated water leakage for ESF components subject to aging management outside Containment
- general-condition-monitoring activities to manage loss of material in stainless steel components (other than piping or tanks) that are exposed externally to atmosphere/weather or intermittent wet/dry air environments
- buried piping and valve inspection activities to manage loss of material from the external surfaces of buried stainless steel piping or valves
- chemistry control program to manage loss of material or cracking in stainless steel components exposed internally to treated-water
- ISI program as an additional program to manage loss of pre-load in ASME Code Class 1 bolting exposed to air environments, cracking in ASME Class 1 stainless steel piping exposed internally to treated-water, or reduction of fracture toughness in ASME Class 1 CASS valves exposed internally to treated-water at temperatures above 482°F (In accordance with 10 CFR 50.55a, to the applicant is required to perform all ISI and IST on ASME Code Class 1, 2 or 3 ESF components that are currently required by its CLB.)
- tank inspection activities as an additional program for managing loss of material of those ESF stainless steel tanks that are exposed internally to treated-water and externally to atmosphere/weather conditions
- infrequent accessed area inspection activities for managing loss of material in stainless steel piping and sump screens exposed to raw water in the containment sump
- work control process as an additional program for managing loss of material in stainless steel piping and valve bodies that are located in the containment sump and exposed internally to raw water, and in stainless steel ESF components that are exposed internally to intermittent wet/dry air environments

For SPS 1/2, the applicant also credits the chemistry control program for primary systems as an additional program for managing loss of material in SPS sensitized stainless steel ESF piping that is exposed internally to treated-water, and both the chemistry control program for primary systems and the augmented inspection activities as additional program for managing cracking in these components. In addition, the applicant identified the following programs to manage cracking or loss of material in the SPS copper-nickel SI pump seal cooler tubes:

- work control process to manage cracking in the external surfaces of the tubes under air environments
- general-condition-monitoring activities to manage loss of material from the external surfaces when exposed to borated water leakage environments
- work control process to manage loss of material from the internal surfaces when exposed to treated-water

The applicant's response to RAI 2.1-3, dated February 1, 2002, has increased the license renewal boundary for four of the ESF systems within the scope of license renewal: (1) QS/CS, (2) RH, (3) FC, and (4) SI. In the response to RAI 2.1-3, the applicant provided the AMRs for the expanded portions of the QS/CS, RH, FC, and SI systems brought within the scope of license renewal as part of the applicant's efforts to resolve the Seismic II/I issue for the

Surry/North Anna LRA. The applicant has identified that the following aging management activities or programs will be used to manage loss of material and/or cracking in the expanded portions of the QS/CS, RH, FC, and SI systems brought within the scope of license renewal:

- general condition monitoring activities and infrequently accessed area inspection activities to manage loss of material from the external surfaces of the stainless steel components
- chemistry control program for primary systems and the work control process to manage loss of material and/or cracking in stainless steel components exposed to treated water

The detailed review performed by staff on individual AMAs and its ability to effectively manage the applicable aging effects is provided in Sections 3.3.1 and 3.3.4 of this SER. However, as part of its review of the applicant's AMR, the staff did verify that the AMAs assigned to the different ESF SCs were consistent with the applicable aging effects. As a result of this review, the staff verified that the AMAs credited for managing the applicable aging effects for the ESF components are consistent with current industry practices. No omissions or concerns were identified with AMAs used to manage the ESF systems.

3.5.3 Conclusions

On the basis of the review described above, the staff concludes that the applicant has performed an AMR that adequately identifies the applicable aging effects for the ESF SCs. In combination with the staff's scoping review, as documented in Section 2.3.2 of this SER, and the staff's aging management activities reviews, as documented in Sections 3.3.1 and 3.3.4 of this SER, the staff concludes that the applicant has demonstrated that there is reasonable assurance that the effects of aging on ESF systems will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

3.6 Aging Management of Auxiliary Systems

The applicant described its aging management review (AMR) of the primary process systems, open water systems, closed-water systems, diesel generator support systems, air and gas systems, and ventilation and vacuum systems for license renewal in nine separate sections of each LRA Section 3.3.1, "Primary Process Systems"; Section 3.3.2, "Open Water Systems"; Section 3.3.3, "Closed-water Systems"; Section 3.3.4, "Diesel Generator Support Systems"; Section 3.3.5, "Air and Gas Systems"; Section 3.3.6, "Ventilation and Vacuum Systems"; Section 3.3.7, "Drain and Liquid Processing Systems"; Section 3.3.8, "Vent and Gaseous Processing System"; and 3.3.9, "Fire Protection and Supporting Systems," of the LRA. Appendices A, B, and C to the LRA also contain supplementary information related to the AMR of the auxiliary systems. The staff reviewed Section 3.3 of each LRA to determine whether the applicant has demonstrated that the effects of aging on these systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

During its review of the summary of the results of the AMR for these systems, the staff determined the need for clarification on the following:

- loss of material is listed as an applicable aging effect for stainless steel components exposed to air (water-laden or intermittent exposure to water)
- the IS program - component and component support inspections is credited for managing the loss of pre-load for bolting
- no aging effects were identified in the application for carbon steel and low-alloy steel components exposed to an external air environment as found in Tables 3.3.7, 3.3.8, and 3.3.9 in both applications

During a telecommunication with the applicant on July 31, and August 8, 2001 (as documented in telecommunication summaries dated August 8, and October 11, 2001) the applicant clarified that:

- the applicant has no operating history of aging of stainless steel components in an air environment (water-laden or intermittently exposed to water); however, these components are managed for potential loss of material to ensure a conservative approach to detect such aging in the period of extended operation
- the intent of crediting the ISI program - component and component support inspections for bolting is to detect gross loss of pre-load (loose bolts) through visual inspections not for detection in a reduction of torque
- the external air environment in Tables 3.3.7, 3.3.8, and 3.3.9 in both applications are sheltered, non-wetted air environments that would not lead to a loss of material for carbon steel and low-alloy steel components

Based on the information provided by the applicant, the staff concluded that the responses are acceptable and that additional information will not be required.

3.6.1 Primary Process Systems

3.6.1.1 Summary of Technical Information in the Application

The applicant described the results of its AMR of the primary process systems for license renewal in Section 3.3.1, "Primary Process Systems," of the LRAs. The staff reviewed this section of each LRA to determine whether the applicant has demonstrated that the effects of aging on the primary process systems (PPS) will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

The PPS is described in the following sections of the LRAs: Section 2.3.3.1 of both LRAs, "Chemical and Volume Control (CH) system"; Section 2.3.3.2 of NAS LRA, "High Radiation Sampling System (HRSS)"; Section 2.3.3.2 of SPS LRA, "Incore Instrumentation (IC) system"; Section 2.3.3.3 of NAS LRA, "Incore Instrumentation (IC) system"; Section 2.3.3.3 of SPS LRA, "Reactor Cavity Purification (RL) system"; Section 2.3.3.4 of NAS LRA, "Refueling Purification (RP) system"; Section 2.3.3.4 of SPS LRA, "Sampling (SS) system"; and Section 2.3.3.5 of NAS LRA, "Sampling (SS) system".

3.6.1.1.1 Aging Effects

The materials of construction for the PPS systems, structures, and components (SSCs) are stainless steel (including cast austenitic stainless steel) with carbon steel, low-alloy steel, cast iron and copper alloys.

In addition, for SPS 1/2 only, nickel-based alloy components are also used and the fabrication process for the PPS piping systems resulted in sensitization of some of the stainless steel material.

A description of the internal environments is provided in Table 3.0-1 of each LRA. The PPS components are exposed to one or more of the following internal environments:

- borated water
- gas
- treated-water
- ambient air
- raw water and lubricating oil for the charging pump lubricating oil cooler (NAS 1/2 only)
- raw water (brackish) and lubricating oil for the charging pump lubricating oil cooler (SPS 1/2 only)

The PPS SSCs external surfaces that require aging management review are located in various indoor areas of the plant including containment. These components are exposed to containment air and sheltered-air environments. The containment air and sheltered-air environments are as indicated in Table 3.0-2 of each LRA.

The following aging effects, associated with PPS SSCs require management:

- change in material properties of copper alloy components in a raw water environment
- cracking of stainless steel (including CASS) components in treated-water, steam or oil environments

- loss of material from carbon steel, low-alloy steel, cast iron, copper alloy, and stainless steel (including CASS) components in raw water, treated-water, steam, oil, or air environments
- loss of material from carbon steel, low-alloy steel, cast iron, and copper alloy components in a borated-water leakage environment
- heat transfer degradation of heat transfer surfaces in a raw water environment
- loss of pre-load of Class 1 bolting exposed to an air environment
- reduction in fracture toughness of CASS components in a high-temperature treated-water environment
- thermal fatigue of piping

In addition, the following aging effects are applicable only for SPS 1/2:

- cracking and loss of material from sensitized stainless steel components in a treated-water environment
- loss of material from nickel-based alloy components in a treated-water environment

3.6.1.1.2 Aging Management Programs

The following aging management activities manage aging effects for the PPS SSCs:

- boric acid corrosion surveillance
- chemistry control program for secondary systems
- chemistry control program for primary systems
- general-condition-monitoring activities
- ISI program - component and component support inspections
- work control process
- augmented inspection activities (SPS 1/2 only)

A description of these aging management programs and activities, along with the demonstration that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of each LRA: Section B2.2.3, "Boric Acid Corrosion Surveillance"; Section B2.2.5, "Chemistry Control Program for Secondary Systems"; Section B2.2.4, "Chemistry Control Program for Primary Systems"; Section B2.2.9, "General-condition-monitoring activities"; Section B2.2.11, "ISI Program - Component and Component Support Inspections"; Section B2.2.19, "Work Control Process"; and Section B2.2.1, "Augmented Inspection Activities." The staff reviewed these sections of each LRA to determine whether the applicant has demonstrated that the effects of aging on the PPS SSCs will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.1.2 Staff Evaluation

3.6.1.2.1 Aging Effects

The aging effects that result from contact of PPS SSCs to environments as shown in Table 3.3.1 are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects listed are appropriate for the combinations of materials and environments listed.

3.6.1.2.2 Aging Management Programs

The aging management programs have been evaluated in Sections 3.3.1 and 3.3.4 of this SER and have been found to be acceptable for managing the aging effects identified for the PPS SSCs.

3.6.1.3 Conclusion

The staff reviewed the information in Section 3.3.1, "Primary Process Systems." On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the PPS SSCs will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.6.2 Open Water Systems

3.6.2.1 Summary of Technical Information in the Application

The applicant described the results of its AMR of the open water systems for license renewal in Section 3.3.2, "Open Water Systems," of each LRA. The staff reviewed this section of each LRA to determine whether the applicant has demonstrated that the effects of aging on the open water systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

The open water systems are described in the following sections of each LRA: Section 2.3.3.21 of NAS LRA, "Heating and ventilation (HV) system"; Section 2.3.3.14 of NAS LRA, "Instrument Air (IA) system"; Section 2.3.3.6 of NAS LRA, "Service water (SW) system"; Section 2.3.4.2 of SPS LRA, "Blowdown (BD) system"; Section 2.3.3.5 of SPS LRA, "Circulating Water (CW) system"; Section 2.3.3.6 of SPS LRA, "Service Water (SW) system"; Section 2.3.3.20 of SPS LRA, "Vacuum Priming (VP) system"; and Section 2.3.3.21 of SPS LRA, "Ventilation (VS) system."

3.6.2.1.1 Aging Effects

The materials of construction for the open water systems SSCs are carbon steel, low-alloy steel, cast iron, stainless steel, copper alloys, and elastomers (rubber). In addition, for SPS 1/2 only, the open water systems SSCs include aluminum, fiberglass, titanium, and nickel-based alloy materials.

A description of the internal environments is provided in Table 3.0-1 of each LRA. The open water systems SSCs are exposed to one or more of the following internal environments:

- raw water
- air
- gas (refrigerant)
- treated-water
- raw water (fresh water) treated to inhibit biological growth and minimize corrosion as the source for HV system chiller condenser cooling water and instrument air compressor cooling water (NAS 1/2 only)

In addition, the following internal environments are applicable only for SPS 1/2:

- raw water (brackish water of the James River) as the source for the CW and SW (including VS chiller condenser cooling water) systems
- fuel oil, lubricating oil, and treated-water (diesel cooling) for SW system diesel engines and auxiliaries
- treated-water for main condenser components
- steam environment on shell-side of the main condenser tubes and tubesheets

The open water systems SSCs external surfaces that require aging management review are located in various indoor areas of the plant including containment. These components are exposed to containment air and sheltered-air environments. In addition, external surfaces of open water systems SSCs may be exposed to borated water leakage conditions and portions of open water systems piping are buried in soil or encased in concrete. These environments, are as indicated in Table 3.0-2 of each LRA.

In addition, some open water systems SSCs found only in NAS 1/2 are externally exposed to the outdoor (atmosphere/weather) environment as indicated in Table 3.0-2. In addition, portions of the SW system piping at the service water reservoir at NAS 1/2 are continually submerged and other piping and components are intermittently wetted by evaporative cooling spray.

The following aging effects, associated with open water systems SSCs require management:

- change in material properties and cracking of elastomeric components in an air environment
- change in material properties of copper alloy components in a raw water environment
- loss of material from carbon steel, low-alloy steel, cast iron, stainless steel, or copper alloy components in raw water or air environments
- heat transfer degradation of heat transfer surfaces in a raw water environment
- loss of material from carbon steel, low-alloy steel, and copper alloy components in a borated water leakage environment

The following aging effects are applicable only for open water systems SSCs at NAS 1/2:

- loss of material from stainless steel components in a treated-water environment
- loss of material from copper alloy components in an atmosphere/weather environment

In addition, the following aging effects are applicable only for open water systems SSCs in SPS 1/2:

- change in material properties and loss of material from copper alloy components in a soil (buried) or treated-water/steam environment
- loss of material from buried stainless steel components in a soil environment
- loss of material from carbon steel, low-alloy steel, cast iron, copper alloy components in an oil environment
- loss of material from nickel-base alloy components in a raw water environment
- loss of material from carbon steel, low-alloy steel, cast iron, or titanium components in treated-water or steam environments

3.6.2.1.2 Aging Management Programs

The following aging management activities manage aging effects for the open water systems SSCs:

- boric acid corrosion surveillance
- buried piping and valve inspection activities
- general-condition-monitoring activities
- infrequently accessed area inspection activities
- service water system inspections
- work control process
- chemistry control program for secondary systems (SPS 1/2 only)
- fuel oil chemistry (SPS 1/2 only)
- tank inspection activities (SPS 1/2 only)

A description of these aging management programs and activities, along with the demonstration that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of each LRA: Section B2.2.3, "Boric Acid Corrosion Surveillance"; Section B2.1.1, "Buried Piping and Valve Inspection Activities"; Section B.2.2.9, "General-condition-monitoring activities"; Section B.2.1.2, "Infrequently Accessed Area Inspection Activities"; Section B2.2.17, "Service Water System Inspections"; Section B2.2.19, "Work Control Process"; Section B2.2.5, "Chemistry Control Program for Secondary Systems"; Section B2.2.8, "Fuel Oil Chemistry"; and Section B2.1.3, "Tank Inspection Activities." The staff reviewed these sections of each LRA to determine whether the applicant has demonstrated that the effects of aging on the open water systems SSCs will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.2.2 Staff Evaluation

3.6.2.2.1 Aging Effects

The aging effects that result from contact with open water system SSCs to environments as shown in Table 3.3.2 are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects are appropriate for the combinations of materials and environments listed.

3.6.2.2.2 Aging Management Programs

The aging management programs have been evaluated in Sections 3.3.1 and 3.3.4 of this SER and have been found to be acceptable for managing the aging effects identified for the open water systems SSCs.

3.6.2.3 Conclusion

The staff reviewed the information in Section 3.3.2, "Open Water System." On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the open water systems SSCs will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.6.3 Closed-water Systems

3.6.3.1 Summary of Technical Information in the Application

The applicant described the results of its AMR of the closed-water systems for license renewal in Section 3.3.3, "Closed-water Systems," of each LRA. The staff reviewed this section of each LRA to determine whether the applicant has demonstrated that the effects of aging on the closed-water systems SSCs will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

The closed-water systems are described in the following sections of each LRA: Section 2.3.3.7 of NAS LRA, "Chilled water (CD) system"; Section 2.3.3.8 of NAS LRA, "Component cooling (CC) system"; Section 2.3.3.17 of NAS LRA, "Containment vacuum (CV) system"; Section 2.3.3.21 of NAS LRA, "Heating and ventilation (HV) system"; Section 2.3.3.9 of NAS LRA, "Neutron shield tank cooling (NS) system"; Section 2.3.1.1 of NAS LRA, "Reactor coolant (RC) system"; Section 2.3.3.7 of SPS LRA, "Bearing Cooling BC) system", Section 2.3.3.8 of SPS LRA, "Component Cooling (CC) system"; Section 2.3.3.14 of SPS LRA, "Instrument Air (IA) system"; Section 2.3.3.9 of SPS LRA, "Neutron Shield Tank Cooling (NS) system"; Section 2.3.3.10 of SPS LRA, "Primary Grade Water (PG) system"; Section 2.3.1.1 of SPS LRA, "Reactor Coolant (RC) system"; and Section 2.3.3.21 of SPS LRA, "Ventilation (VS) system."

3.6.3.1.1 Aging Effects

The materials of construction for the closed-water systems SSCs are carbon steel, low-alloy steel, cast iron, stainless steel, copper alloys, and titanium.

A description of the internal environments is provided in Table 3.0-1 of each LRA. The closed-water systems SSCs are exposed to one or more of the following internal environments:

- treated-water (bearing cooling/chilled water)
- treated-water (component cooling)
- raw water
- gas (refrigerant)

The closed-water systems SSCs external surfaces that require aging management review are located in indoor areas of the plant including containment. These components are exposed to air and Containment air environments. The sheltered-air and Containment air environments, are indicated in Table 3.0-2 of each LRA. External surfaces of closed-water systems SSCs may also be exposed to borated water leakage conditions.

The following aging effects, associated with closed-water systems SSCs require management:

- loss of material from carbon steel, low-alloy steel, cast iron, stainless steel, titanium, and copper alloy components in treated-water or air environments
- loss of material from carbon steel and low-alloy steel components in a raw water environment

- loss of material from carbon steel, low-alloy steel, cast iron, and copper alloy components in a borated-water leakage environment
- heat transfer degradation of heat transfer surfaces in a raw water environment
- loss of material from stainless steel and copper alloy components in a raw water environment. (NAS 1/2)

3.6.3.1.2 Aging Management Programs

The following aging management activities manage aging effects for the closed-water systems SSCs:

- boric acid corrosion surveillance
- chemistry control program for secondary systems
- chemistry control program for primary systems
- general-condition-monitoring activities
- infrequently accessed area inspection activities
- service water system inspections
- work control process

A description of these aging management programs and activities, along with the demonstration that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of each LRA: Section B2.2.3, "Boric Acid Corrosion Surveillance"; Section B2.2.5, "Chemistry Control Program for Secondary Systems"; Section B2.2.4, "Chemistry Control Program for Primary Systems"; Section B2.2.9, "General-condition-monitoring activities"; Section B2.1.2, "Infrequently Accessed Area Inspection Activities"; Section B2.2.17, "Service Water System Inspections"; and Section B2.2.19, "Work Control Process." The staff reviewed these sections of each LRA to determine whether the applicant has demonstrated that the effects of aging on the closed-water systems SSCs will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.3.2 Staff Evaluation

3.6.3.2.1 Aging Effects

The aging effects that result from contact of closed-water systems SSCs to environments as shown in Table 3.3.3 are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects are appropriate for the combinations of materials and environments.

3.6.3.2.2 Aging Management Programs

The aging management programs have been evaluated in Sections 3.3.1 and 3.3.4 of this SER and have been found to be acceptable for managing the aging effects identified for the closed-water systems SSCs.

3.6.3.3 Conclusion

The staff reviewed the information in Section 3.3.3, "Closed-water Systems." On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the closed-water systems SSCs will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.6.4 Diesel Generator Support Systems

3.6.4.1 Summary of Technical Information in the Application

The applicant described the results of its AMR of the diesel generator support systems for license renewal in Section 3.3.4, "Diesel Generator Support Systems," of each LRA. The staff reviewed this section of each LRA to determine whether the applicant has demonstrated that the effects of aging on the diesel generator support systems (DGSS) will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

The DGSS are described in the following sections of each LRA: Section 2.3.3.10, "Alternate AC (AAC) Diesel Generator Systems"; Section 2.3.3.11, "Emergency Diesel Generator (EDG) Systems"; and Section 2.3.3.13, "Security (SEC) System".

3.6.4.1.1 Aging Effects

The materials of construction for the DGSS SSCs are carbon steel, low-alloy steel, cast iron, stainless steel, copper alloys, and aluminum.

A description of the internal environments is provided in Table 3.0-1 of each LRA. The DGSS SSCs are exposed to one or more of the following internal environments:

- compressed air
- lubricating or fuel oil
- treated-water (diesel cooling)
- raw water
- ambient air

The DGSS SSCs external surfaces that require aging management review are located in indoor and outdoor areas of the plant. These components are exposed to air, and atmosphere/weather environments. The sheltered-air and outdoor (atmosphere/weather) environments are as indicated in Table 3.0-2 of each LRA. Portions of DGSS piping are buried in soil and are exposed to a soil environment.

The following aging effects, associated with DGSS SSCs require management:

- cracking of copper alloy components in an air environment
- loss of material from carbon steel, low-alloy steel, cast iron, stainless steel, and copper alloy components in oil, air, treated-water, raw water, soil, or atmosphere/weather environments
- cracking of copper alloy components in an atmosphere/weather environment (SPS 1/2)

3.6.4.1.2 Aging Management Programs

The following aging management activities manage aging effects for the DGSS SSCs:

- buried piping and valve inspection activities
- chemistry control program for secondary systems
- fuel oil chemistry
- general-condition-monitoring activities
- tank inspection activities
- work control process

A description of these aging management programs and activities, along with the demonstration that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of each LRA: Section B2.1.1, "Buried Piping and Valve Inspection Activities"; Section B2.2.5, "Chemistry Control Program for Secondary Systems"; Section B2.2.8, "Fuel Oil Chemistry"; Section B2.2.9, "General-condition-monitoring activities"; Section B2.1.3, "Tank Inspection Activities"; and Section B2.2.19, "Work Control Process." The staff reviewed these sections of each LRA to determine whether the applicant has demonstrated that the effects of aging on the DGSS SSCs will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.4.2 Staff Evaluation

3.6.4.2.1 Aging Effects

The aging effects that result from contact of DGSS SSCs to environments as shown in Table 3.3.4 of each LRA are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects are appropriate for the combinations of materials and environments.

3.6.4.2.2 Aging Management Programs

The aging management programs for the DGSS SSCs have been evaluated in Sections 3.3.1 and 3.3.4 of this SER and have been found to be acceptable for managing the aging effects identified for the DGSS SSCs.

3.6.4.2.3 Conclusion

The staff reviewed the information in Section 3.3.4, "Diesel Generator Support Systems." On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the DGSS SSCs will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.6.5 Air and Gas Systems

3.6.5.1 Summary of Technical Information in the Application

The applicant described the results of its AMR of the air and gas systems for license renewal in Section 3.3.5, "Air and Gas Systems," of each LRA. The staff reviewed this section of each LRA to determine whether the applicant has demonstrated that the effects of aging on the air and gas systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

The air and gas systems are described in the following sections of each LRA: Section 2.3.3.13, "Compressed air (CA) system"; Section 2.3.4.4, "Feedwater (FW) system"; Section 2.3.3.21, "Heating and ventilation (HV) system"; Section 2.3.3.14, "Instrument air (IA) system"; Section 2.3.3.15, "Primary and secondary plant gas supply (GN) system"; and Section 2.3.1.1, "Reactor coolant (RC) system"; and Section 2.3.3.16, "Service air (SA) system.

3.6.5.1.1 Aging Effects

The materials of construction for the air and gas systems SSCs are rubber, carbon steel, low-alloy steel, stainless steel, copper alloys, and aluminum.

The air and gas system SSCs are exposed to one or more of the internal environments described in Table 3.0-1 of each LRA.

The internal environment for the air and gas systems SSCs is compressed dry air or gas, with the exception of SA system components environment which is considered moisture-laden air since there are no dryers in the system. The air and gas systems SSCs that require aging management review are located in the containment and other indoor areas of the plant, and are exposed to an air environment. The containment air environment, and the sheltered-air environment used for areas outside containment, are as indicated in Table 3.0-2 of each LRA.

External surfaces of air and gas systems SSCs may also be exposed to borated water leakage conditions.

The following aging effects, associated with the air and gas systems, require management:

- cracking and change in material properties of rubber components in an air environment
- loss of material from carbon steel, low-alloy steel, and copper alloy components in a borated water leakage environment
- loss of material from stainless steel components in an air environment (NAS 1/2)
- loss of material from copper alloy components in an air environment (SPS 1/2)

3.6.5.1.2 Aging Management Programs

The following aging management activities manage aging effects for the air and gas systems SSCs:

- boric acid corrosion surveillance
- general condition monitoring
- work control process

A description of these aging management programs and activities, along with the demonstration that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of each LRA: Section B2.2.3, "Boric Acid Corrosion Surveillance"; Section B2.2.9, "General-condition-monitoring activities"; and Section B2.2.19, "Work Control Process." The staff reviewed these sections of each LRA to determine whether the applicant has demonstrated that the effects of aging on the air and gas systems SSCs will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.5.2 Staff Evaluation

3.6.5.2.1 Aging Effects

The aging effects that result from contact of air and gas systems SSCs to environments as shown in Table 3.3.5 of each LRA are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects are appropriate for the combinations of materials and environments listed.

3.6.5.2.2 Aging Management Programs

The aging management programs for the air and gas systems SSCs have been evaluated in Section 3.3.1 of this SER and have been found to be acceptable for managing the aging effects identified for the air and gas systems SSCs.

3.6.5.2.3 Conclusion

The staff reviewed the information in Section 3.3.5, "Air and Gas Systems." On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the air and gas systems will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.6.6 Ventilation and Vacuum Systems

3.6.6.1 Summary of Technical Information in the Application

The applicant described the results of its AMR of the ventilation and vacuum systems for license renewal in Section 3.3.6, "Ventilation and Vacuum Systems," of each LRA. The staff reviewed this section of each LRA to determine whether the applicant has demonstrated that the effects of aging on the ventilation and vacuum systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

The ventilation and vacuum systems are described in the following sections of each LRA: Section 2.3.3.17, "Containment Vacuum (CV) system"; Section 2.3.3.18, "Leakage monitoring

(LM) system"; Section 2.3.3.19, "Secondary Vent (SV) system"; Section 2.3.3.20, "Vacuum priming (VP) system"; and Section 2.3.3.21, "Heating and ventilation (HV) system."

3.6.6.1.1 Aging Effects

The materials of construction for the ventilation and vacuum systems SSCs are carbon steel, low-alloy steel, copper alloys, stainless steel, and elastomeric (rubber) materials. Aluminum is used in the ventilation and vacuum systems at NAS 1/2. Cast iron is also used at SPS 1/2 in ventilation and vacuum systems SSCs.

The internal environment for the ventilation and vacuum systems SSCs is air or gas, with the exception of the HV system chiller compressors which are subjected to a refrigerant (freon gas) internal environment. A description of internal environments is provided in Table 3.0-1 of each LRA.

The ventilation and vacuum systems SSCs that require aging management review are located in the containment and other indoor areas of the plant, and outdoors. These components are exposed to an air environment. The containment air environment, and the sheltered-air and outdoor (atmosphere/weather) environments are as indicated in Table 3.0-2 of each LRA.

External surfaces of ventilation and vacuum systems SSCs may also be exposed to borated water leakage conditions.

The following aging effects, associated with the ventilation and vacuum systems SSCs, require management:

- loss of material from carbon steel, low-alloy steel, and copper alloy components in a borated water leakage environment
- loss of material from carbon steel and low-alloy steel components in an air or atmosphere/weather environment
- cracking and change in material properties of rubber components in an air or atmosphere/weather environment

In addition, the following aging effects require management only at SPS 1/2:

- loss of material from carbon steel and low-alloy steel components in an air or atmosphere/weather environment
- loss of material from cast iron components in an air environment

3.6.6.1.2 Aging Management Programs

The following aging management activities manage aging effects for the ventilation and vacuum systems SSCs:

- boric acid corrosion surveillance
- general condition monitoring
- work control process

A description of these aging management programs and activities, along with the demonstration that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of each LRA: Section B2.2.3, "Boric Acid Corrosion Surveillance"; Section B2.2.9, "General-condition-monitoring activities"; and Section B2.2.19, "Work Control Process." The staff reviewed these sections of each LRA to determine whether the applicant has demonstrated that the effects of aging on the ventilation and vacuum systems SSCs will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.6.2 Staff Evaluation

3.6.6.2.1 Aging Effects

The aging effects that result from contact of ventilation and vacuum systems SSCs to environments as shown in Table 3.3.6 are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects are appropriate for the combinations of materials and environments listed.

3.6.6.2.2 Aging Management Programs

The aging management programs have been evaluated in Section 3.3.1 of this SER and have been found to be acceptable for managing the aging effects identified for the ventilation and vacuum systems SSCs.

3.6.6.2.3 Conclusion

The staff reviewed the information in Section 3.3.6, "Ventilation and Vacuum Systems." On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the ventilation and vacuum systems will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.6.7 Drain and Liquid Processing Systems

3.6.7.1 Summary of Technical Information in the Application

The applicant described the results of its AMR of the drain and liquid processing systems for license renewal in Section 3.3.7, "Drain and Liquid Processing Systems," of each LRA. The staff reviewed this section of each LRA to determine whether the applicant has demonstrated that the effects of aging on the drain and liquid processing systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

The drain and liquid processing systems are described in the following sections of each LRA: Section 2.3.3.22 of SPS LRA, "Boron Recovery System"; Section 2.3.3.23 of SPS LRA, "Drains-Aerated System"; Section 2.3.3.24 of SPS LRA, "Drains-Gaseous System"; Section 2.3.3.25 of SPS LRA, "Plumbing System"; Section 2.3.3.22 of NAS LRA, "Boron Recovery (BR) system"; Section 2.3.3.23 of NAS LRA, "Drains - Aerated (DA) system"; Section 2.3.3.24 of NAS LRA, "Drains - Building Services (DB) system"; Section 2.3.3.25 of NAS LRA, "Drains - Gaseous

(DG) system"; Section 2.3.3.26 of NAS LRA, "Liquid and Solid Waste (LW) system" and Section 2.3.3.27 of NAS LRA, "Radwaste (RW) system."

3.6.7.1.1 Aging Effects

The materials of construction for the drain and liquid processing system components are stainless steel, carbon steel, and low-alloy steel. For SPS 1/2, fiberglass material is also used.

A description of the internal environments to the drain and liquid processing systems is provided in Table 3.0-1 of each LRA. The system components are exposed internally to one or more of the following environments:

- treated-water (borated water)
- gas
- treated-water (component cooling)
- air
- steam

External surfaces of the drain and liquid processing system structures and components that require aging management review are exposed to the containment air environment and sheltered-air environment for areas outside containment. The external surfaces of the system component may also be exposed to borated water leakage conditions. These environments are discussed in Table 3.0-2 of each LRA.

The applicant identified the following aging effects associated with the drain and liquid processing systems that require management:

- cracking of stainless steel components in a steam environment
- loss of material from carbon steel, low-alloy steel, and stainless steel components in air, gas, raw water, steam, or treated-water environments
- loss of material from carbon steel and low-alloy steel components in a borated water leakage environment

3.6.7.1.2 Aging Management Programs

The applicant identified the following aging management activities to manage aging effects for the drain and liquid processing systems:

- boric acid corrosion surveillance
- chemistry control program for primary systems
- general-condition-monitoring activities
- work control process

A description of these aging management programs and activities, along with the demonstration that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of each LRA: Section B2.2.3, "Boric Acid Corrosion Surveillance"; Section B2.2.4, "Chemistry Control Program for Primary Systems"; Section B2.2.9, "General-condition-monitoring activities"; and Section B2.2.19, "Work Control Process". The staff reviewed these sections of the LRAs to determine whether the applicant has demonstrated that the effects of aging on the drain and liquid processing system structures and components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.7.2 Staff Evaluation

3.6.7.2.1 Aging Effects

The aging effects that result from contact of the drain and liquid processing system structures and components to environments as shown in Table 3.3.7 of each LRA are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects are appropriate for the combinations of materials and environments listed.

3.6.7.2.2 Aging Management Programs

The aging management programs for the drain and liquid processing systems SSCs have been evaluated in Section 3.3.1 of this SER and found to be acceptable for managing the aging effects identified for the drain and liquid processing systems SSCs.

3.6.7.3 Conclusion

The staff reviewed the information in Section 3.3.7, "Drain and Liquid Processing Systems," of each LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the drain and liquid processing system structures and components will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.6.8 Vent and Gaseous Processing Systems

3.6.8.1 Summary of Technical Information in the Application

The applicant described the results of its AMR of the vent and gaseous processing systems for license renewal in Section 3.3.8, "Vent and Gaseous Processing Systems," of each LRA. The staff reviewed this section of each LRA to determine whether the applicant has demonstrated that the effects of aging on the vent and gaseous processing systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

The vent and gaseous processing systems are described in the following sections of each LRA: Section 2.3.3.26 of SPS LRA, "Gaseous Waste System"; Section 2.3.3.27 of SPS LRA, "Radiation Monitoring System"; Section 2.3.3.28 of SPS LRA, "Vents-Aerated System"; Section 2.3.3.29 of SPS LRA, "Vents-Gaseous System; Section 2.3.3.28 of NAS LRA, "Post-Accident Hydrogen Removal (HC) system"; Section 2.3.3.29 of NAS LRA, "Radiation Monitoring (RM) system"; and Section 2.3.3.30 of NAS LRA, "Vents – Gaseous (VG) systems."

3.6.8.1.1 Aging Effects

The materials of construction for the vent and gaseous processing system components are carbon steel, low-alloy steel, and stainless steel. In addition, for SPS 1/2, the copper alloy materials are also used.

A description of internal environments for the vent and gaseous processing systems is provided in Table 3.0-1 of each LRA. The vent and gaseous processing systems components are exposed internally to air, and vent gases from various process systems, and air from the containment atmosphere. In addition, the system components in SPS 1/2 are exposed internally to treated-water (component cooling).

External surfaces of the vent and gaseous processing systems components that require aging management review are exposed to containment air environment, and the sheltered-air environment used for indoor areas outside containment. External surfaces of the system components may also be exposed to borated water leakage conditions. The external environments are indicated in Table 3.0-2 of each LRA.

The applicant identified loss of material from carbon steel and low-alloy steel components as the applicable aging effect associated with the vent and gaseous processing systems which requires management.

In addition, the following aging effects are applicable to the vent and gaseous processing systems only at SPS 1/2:

- loss of material from stainless steel components in a treated-water environment
- loss of material from copper alloy components in a borated water leakage environment

3.6.8.1.2 Aging Management Programs

The applicant identified the following aging management activities to manage aging effects for the vent and gaseous processing systems:

- boric acid corrosion surveillance
- chemistry control program for primary systems (applicable to SPS 1/2 only)
- general-condition-monitoring activities

A description of these aging management programs and activities, along with the demonstration that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of each LRA: Section B2.2.3, "Boric Acid Corrosion Surveillance"; Section B2.2.4, "Chemistry Control Program for Primary Systems"; and Section B.2.2.9, "General-condition-monitoring activities". The staff reviewed these sections of each LRA to determine whether the applicant has demonstrated that the effects of aging on the vent and gaseous processing system components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.8.2 Staff Evaluation

3.6.8.2.1 Aging Effects

The aging effects that result from exposing the vent and gaseous processing system components to environments as shown in Table 3.3.8 of each LRA are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects are appropriate for the combinations of materials and environments listed.

3.6.8.2.2 Aging Management Programs

The aging management programs for the vent and gaseous processing systems SSCs have been evaluated in Section 3.3.1 of this SER and have been found to be acceptable for managing the aging effects identified for the vent and gaseous processing systems SSCs.

3.6.8.3 Conclusion

The staff reviewed the information in Section 3.3.8, "Vent and Gaseous Processing Systems," of each LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the vent and gaseous processing system structures and components will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.6.9 Fire Protection and Supporting Systems

3.6.9.1 Summary of Technical Information in the Application

The applicant described the results of its AMR of the fire protection and supporting systems for license renewal in Section 3.3.9, "Fire Protection and Supporting Systems," of each LRA. The staff reviewed this section of each LRA to determine whether the applicant has demonstrated that the effects of aging on the fire protection and supporting system structures and components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

The fire protection and supporting systems are described in the following sections of each LRA: Section 2.3.3.30 of SPS LRA, "Fire Protection System"; Section 2.3.3.31 of SPS LRA, "Hydrogen Gas System"; Section 2.3.3.31 of NAS LRA, "Post-accident Hydrogen Removal (HC) system"; and Section 2.3.1.1 of NAS LRA, "Reactor Coolant (RC) system: RCP Oil Collection."

3.6.9.1.1 Aging Effects

The materials of construction for the fire protection and supporting system components are carbon steel, low-alloy steel, cast iron, stainless steel, and copper alloys.

A description of the internal environments for the fire protection and supporting systems is provided in Table 3.0-1 of each LRA. The system structures and components are exposed internally to raw water, treated-water (diesel cooling), gas, air, lubricating oil, and fuel oil.

The external surfaces of the fire protection and supporting system components that require aging management review are exposed to containment air, sheltered-air, and outdoor (atmosphere/weather) environments. Portions of the fire protection and supporting system piping and valves are buried and are exposed to a soil environment. The components may also be exposed to borated water leakage conditions. These external environments are discussed in Table 3.0-2 of each LRA.

The applicant identified the following aging effects associated with the fire protection and supporting systems that require management:

- loss of material from carbon steel, low-alloy steel, cast iron, stainless steel, and copper alloy components in raw water, treated-water, oil, gas, air, atmosphere/weather, or soil environments
- loss of material from carbon steel, low-alloy steel, and copper alloy components in a borated water leakage environment
- heat transfer degradation of heat transfer surfaces in a raw water environment

3.6.9.1.2 Aging Management Programs

The applicant identified the following aging management activities to manage aging effects for the fire protection and supporting systems:

- boric acid corrosion surveillance
- buried piping and valve inspection activities
- general-condition-monitoring activities
- fuel oil chemistry
- fire protection program
- tank inspection activities

A description of these aging management programs and activities, along with the demonstration that the identified aging effects will be effectively managed for the period of extended operation, is provided in the following sections of each LRA: Section B2.1.1, "Buried Piping and Valve Inspection Activities"; Section B2.1.3, "Tank Inspection Activities"; Section B2.2.3, "Boric Acid Corrosion Surveillance"; Section B2.2.7, "Fire protection program"; Section B2.2.8, "Fuel Oil Chemistry"; and Section B2.2.9, "General-condition-monitoring activities". The staff reviewed these sections of each LRA to determine whether the applicant has demonstrated that the effects of aging on the fire protection and supporting system structures and components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.9.2 Staff Evaluation

3.6.9.2.1 Aging Effects

The aging effects that result from contact of the fire protection and supporting system structures and components with the environments shown in Table 3.3.9-1 of each LRA, are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects are appropriate for the combinations of materials and environments listed.

3.6.9.2.2 Aging Management Programs

The aging management programs for the fire protection and supporting system components have been evaluated in Section 3.3.1.7 of this SER and have been found to be acceptable for managing the aging effects identified for the fire protection and supporting system components.

3.6.9.3 Conclusion

The staff reviewed the information in Section 3.3.9, "Fire Protection and Supporting Systems," of each LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the fire protection and supporting system structures and components will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.6.10 Criterion 2 Components

The staff requested the applicant to address non-safety-related (NSR) piping systems which are not connected to safety-related (SR) piping but have a spatial relationship such that their failure could adversely impact the performance of an intended safety function. In RAI 2.1-3, the staff presented two options to address this concern when performing this scoping evaluation; i.e., a mitigative option or a preventive option.

To utilize the mitigative option, the applicant should demonstrate that the mitigating devices are adequate to protect SR systems, structures, and components (SSCs) from failures of NSR piping segments at any location where age-related degradation is plausible. The preventive option requires that the entire NSR piping system be brought into the scope of license renewal (LR) and an aging management review (AMR) be performed on the components within the piping system.

In its response, the applicant modified the scope of license renewal to include NSR SSCs that have a spatial relationship with SSCs within the scope of LR based on 10 CFR 54.4(a)(1) and whose failure could impact the performance of an intended safety function. In addition, the NSR SSCs are included within the scope of LR using the preventive option described in the staff's RAI. No new material/environment combinations or aging management activities were identified as a result of the expanded scope. This information is documented in the applicant's February 1, May 22, and August 23, 2002, supplemental responses to RAI 2.1-3. Details on the SSCs added into the scope of the LRA as a result of this reevaluation are provided in Section 2.3.5 of this SER.

3.6.10.1 Summary of Technical Information

Table 2.1.3-2, "Systems with Increased License Renewal Boundary Due to Expansion of Criterion 2 Scope," in the response to RAI 2.1-3, identifies systems that were previously within the scope of license renewal and for which the boundary has been extended to include additional components.

For NAS 1/2, the boundaries of the following systems were expanded:

- Primary Process Systems
  - chemical and volume control system
  - high radiation sampling system
  - sampling system

- Open Water Systems
  - service water system

- Closed Water Systems
  - component cooling system
  - chilled water system
  - containment vacuum system
  - reactor coolant system

- Vent and Gaseous Processing System
  - gaseous waste system

- Drain and Liquid Processing Systems
  - boron recovery system
  - plumbing

For SPS 1/2, the boundaries of the following systems were expanded:

- Primary Process Systems
  - chemical and volume control system
  - sampling system

- Open Water Systems
  - service water system

- Closed Water Systems
  - component cooling system
  - containment vacuum system

- Ventilation and Vacuum Systems
  - vacuum priming system

- Drain and Liquid Processing Systems
  - boron recovery system

For NAS 1/2, the following systems were added to the auxiliary systems due to expansion of the LR scope:

- bearing and cooling system
- gaseous waste system
- decontamination system

For SPS 1/2, the following systems were added to the auxiliary systems due to expansion of the LR scope:

- chilled water system
- decontamination system
- liquid waste system

The staff reviewed the supplemental information to determine whether the applicant has demonstrated that the effects of aging on the components in these systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

The applicant's AMR for these systems added to the auxiliary systems is found in the following LRA tables: Table N3.3.3-7, "Closed Water Systems - Bearing Cooling: Additional Criterion 2 (Spatial Orientation) In-Scope Components"; Table N3.3.8-4, "Vent and Gaseous Processing Systems - Gaseous Waste: Additional Criterion 2 (Spatial Orientation) In-Scope Components"; Table N3.3.10, "Decontamination Systems: Additional Criterion 2 (Spatial Orientation) In-Scope Components"; Table S3.3.3-8, "Closed Water Systems - Chilled Water: Additional Criterion 2 (Spatial Orientation) In-Scope Components"; Section S3.3.10, "Decontamination Systems: Additional Criterion 2 (Spatial Orientation) In-Scope Components"; and Table S3.3.11, "Liquid Waste Systems: Additional Criterion 2 (Spatial Orientation) In-Scope Components." The letters "N" and "S" before the table numbers stand for NAS and SPS.

3.6.10.1.1 Aging Effects

The aging effects for components in those systems whose boundaries have been extended as a result of the reevaluation are documented in the original submittal and discussed in Sections 3.6.1 through 3.6.9 of this SER.

The aging effects associated with the Criterion 2 components added to the auxiliary systems are discussed below.

For NAS 1/2 only:

- The materials of construction in the bearing cooling system of the closed water systems are carbon steel, low-alloy steel, cast iron, copper alloys, and stainless steel. These components are exposed internally to treated water and externally to air. The aging effect that requires management for this system is loss of material.

- The materials of construction in the gaseous waste system of the vent and gaseous processing systems are stainless steel, carbon steel, low-alloy steel, cast iron, and copper alloys. These components are exposed internally to gas and externally to air and/or borated water leakage. The aging effect that requires management for this system is loss of material.

For SPS 1/2 only:

- The materials of construction in the chilled water system of the closed water systems are carbon steel, low-alloy steel, cast iron, copper alloys, and stainless steel. These components are exposed internally to treated water/steam and externally to air or borated water leakage. The aging effect that requires management for this system is loss of material.

- The material of construction in the liquid waste systems is stainless steel. These components are exposed internally to treated or raw water and externally to air. The aging effect that requires management for this system is loss of material.

The material of construction for Criterion 2 components in the NAS 1/2 and SPS 1/2 decontamination system is stainless steel. These components are exposed internally to raw water and externally to air. The aging effect that requires management for this system is loss of material.

3.6.10.1.2 Aging Management Programs

The aging management activities for those systems whose boundaries have been extended due to the reevaluation are described in the original submittal and discussed in Sections 3.6.1 through 3.6.9 of this SER.

One or more of the following aging management activities manage aging effects for Criterion 2 components added to the auxiliary systems:

- general condition monitoring activities
- chemistry control for primary systems
- work control process
- infrequently accessed area inspection activities

Descriptions of these aging management programs and activities along with demonstrations that the identified aging effects will be effectively managed for the period of extended operation are provided in the following sections of the LRA: Section B2.2.5, "Chemistry Control Program for Secondary Systems"; Section B2.2.4, "Chemistry Control Program for Primary Systems"; Section B2.2.9, "General Condition Monitoring Activities"; Section B2.1.2, "Infrequently Accessed Area Inspection Activities"; and Section B2.2.19, "Work Control Process." The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the Criterion 2 components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.10.2 Staff Evaluation

3.6.10.2.1 Aging Effects

For those systems whose boundaries have been extended as a result of the reevaluation, the staff's findings are provided in Sections 3.6.1 through 3.6.9 of this SER.

The aging effects that result from the components added to the auxiliary systems as shown in the supplemental tables are, in general, consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects discussed in Section 3.6.10.1.1 are appropriate for the combinations of materials and environments listed.

3.6.10.2.2 Aging Management Programs

The aging management programs are evaluated in 3.3.1 and 3.3.4 of this SER and have been found to be acceptable for managing the aging effects identified for the Criterion 2 components as discussed in Section 3.6.10.1.2.

3.6.10.3 Conclusion

The staff reviewed the supplemental information related to RAI 2.1-3. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the Criterion 2 components will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.7 Aging Management of Steam and Power Conversion Systems

In the North Anna and Surry LRAs, Section 2.3.4, "Steam and Power Conversion Systems," the applicant describes the results of the scoping and screening of the steam and power conversion system (SPCS) SSCs that are within the scope of license renewal and the SPCS SCs that are subject to an AMR. The applicant described its AMR for the SPCS SCs in Section 3.4, "Steam and Power Conversion Systems" of its LRAs. The various AMAs used to manage the aging of the SPCS SCs are described in Appendix B of each LRA as applicable.

The staff review of the scoping and screening results for NAS 1/2 and SPS 1/2 SPCS systems are described in Section 2.3.4 of this SER. The staff's review of the applicant's AMR activities for the NAS 1/2 and SPS 1/2 SPCS systems are the subject of this section of the SER. This review is being performed to determine if the applicant has demonstrated that the effects of aging for the SCs of the SPCSs that are subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation in accordance with 10 CFR 54.21(a)(3).

3.7.1 Summary of Technical Information in the Application

In the North Anna and Surry LRAs, Section 2.3.4, "Steam and Power Conversion Systems," the applicant identified seven systems that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4. The seven systems are auxiliary steam (AS), blowdown (BD), condensate (CN), feedwater (FW), main steam (MS), steam drain, and steam generator water treatment (WT). A brief description of the systems is provided in each LRA and is given below.

Auxiliary Steam System: The AS system supplies low pressure, saturated steam to various plant systems. The portion of the AS system subject to AMR includes the steam pressure regulating valve and associated bypass and isolation valves that are credited with providing a main steam system pressure boundary function in the event of a station blackout (SBO) event or severe fire (Appendix R) event. The component groups for this system that require an AMR are listed in Table 2.3.4-1, Auxiliary Steam. The table identifies the "passive functions" and a reference to the applicable AMR section in each LRA for each component group.

Blowdown System: The BD system provides a flowpath for the continuous blowdown flow from the steam generator secondary-side to maintain acceptable steam generator water chemistry. The BD system isolates flow for containment isolation, to maintain steam generator inventory during transients, and in the event of a high-energy-line break. The portion of the BD system subject to AMR consists of the components from the steam generator to the first manual isolation valves downstream of the outboard containment isolation valves. The portion of the BD system that provides the CC system pressure boundary at the BD system vent condenser is also subject to AMR. The component groups for this system that require an AMR are listed in Table 2.3.4-2, Blowdown. The table identifies the "passive functions" and a reference to the applicable AMR section in each LRA for each component group.

Condensate System: The primary purpose of the CN system is to provide chemically treated-water to the suction of the main feedwater pumps at sufficient pressure to support main feedwater pump operation. The CN system also provides the piping, valves, water storage, and make-up supply for auxiliary feedwater. An emergency condensate storage tank is provided for each Unit. Each tank supplies water to the three auxiliary feedwater pumps through individual lines. These tanks and the associated components up to the suction of the pumps comprise the portion of the CN system that is subject to AMR. The component groups for this system that require an AMR are indicated in Table 2.3.4-3, Condensate. The table identifies the "passive functions" and a reference to the applicable AMR section in each LRA for each component group.

Feedwater System: The FW system is comprised of main feedwater and auxiliary feedwater. Main feedwater provides treated-water to maintain inventory in the steam generators (SG) for the production of steam and to provide a heat sink for the reactor coolant system. Main feedwater components provide a flowpath for auxiliary feedwater flow to the steam generator and provide isolation of main feedwater flow in response to plant transients. Auxiliary feedwater provides an emergency source of water to the SG for reactor heat removal. Auxiliary feedwater provides a heat sink during design basis accidents including loss of power conditions.

The portion of the FW system subject to AMR includes the components from the high-energy line break (HELB) outside of the Containment downstream to the SG feedwater nozzle, and the auxiliary feedwater pumps and discharge line components up to the feedwater piping connection. In addition, back-up compressed air components required for the functioning of selected feedwater isolation valves are subject to an AMR. The component groups for this system that require AMR are identified in Table 2.3.4-4, "Feedwater." The table provides the "passive functions" and a reference to the applicable AMR section in each LRA for each component group.

The auxiliary feedwater system consists of three auxiliary feedwater pumps and associated components. The source of water is provided from the emergency condensate storage tank in the condensate (CN) system. The auxiliary feedwater pumps lubricating oil and seal cooling components support the intended function of those pumps and are also subject to AMR. Because auxiliary feedwater is needed to respond to design basis events, this system is within the scope of license renewal.

Main Steam System: The MS system transports the steam produced in steam generators to the main turbine for the production of electricity. Additionally, the MS system:

- provides motive steam to the turbine-driven auxiliary feed pump
- removes heat from the reactor coolant system via the code safety valves, sg power-operated relief valves (PORVs), and/or condenser steam dump valves
- isolates steam flow to the main turbine following a reactor trip or during accident conditions to prevent an excessive cooldown that could have an adverse effect on the reactor

The major flowpaths of the MS system from the steam generator outlet nozzle to the turbine stop valves and the condenser steam dump valves are subject to AMR. The evaluation boundary extends beyond the safety-related boundary of the system based on high-energy line break (HELB), station blackout (SBO), and Appendix R requirements. The component groups for this system that require an AMR are indicated in Table 2.3.4-5, "Main Steam". The table identifies the "passive functions" and a reference to the applicable AMR section in each LRA for each component group.

Steam Drain System: The SD system provides a flowpath for returning condensate drips from various steam sources to the CN system. The portions of the SD system that are subject to AMR are steam trap drain line piping sections that form the MS system pressure boundary upstream of the main steam trip valves. The component groups for this system that require an AMR are indicated in Table 2.3.4-6, Steam Drains. The table identifies the "passive functions" and a reference to the applicable AMR section in each LRA for each component group.

Steam Generator Water Treatment System: The purpose of the WT system is to provide a means of recirculating water in the steam generator during periods of wet layup to help maintain steam generator water chemistry within limits and to provide the capability for water transfer from the steam generator. The portion of the WT system that is subject to AMR provides the steam generator pressure boundary and the Containment pressure boundary. The component groups for this system that require an AMR are indicated in Table 2.3.4-7, Steam Generator Water Treatment. The table identifies the "passive functions" and a reference to the applicable AMR section in each LRA for each component group.

3.7.1.1 Aging Effects

In the North Anna and Surry LRAs, Section 3.4, the applicant provides a summary of the results of the AMR for the SCs of the SPCSs. The AMR results are listed in each LRAs on Tables 3.4-1 through 3.4-7. The tables provide the following information related to each component commodity group: (1) the "passive functions", (2) the material group, (3) the environment, (4) the aging effects requiring management, and (5) the specific activities that manage the identified aging effects.

<u>Materials</u>

The materials of construction for the SPCS components that are subject to AMR include carbon steel, low-alloy steel, and stainless steel. Copper alloys and nickel-based alloy materials are also used.

Environments

In the North Anna and Surry LRAs, Table 3.0-1, "Internal Service Environment," and Table 3.0-2, "External Service Environment," the applicant states that SPCS components, subjected to an AMR, are exposed to the following environments:

Internal Environments

The normal internal operating conditions for the SPCS components that require an AMR are as follows:

- condensate and auxiliary feedwater components are exposed to treated-water with saturated oxygen concentrations at ambient temperature with typically stagnant flow conditions. Auxiliary feedwater lubricating oil components are exposed to oil at ambient temperature during auxiliary feedwater standby conditions, but may experience elevated temperatures during system operation. Low points in the system may experience water-pooling
- main feedwater and blowdown components are exposed to treated-water (secondary) with low oxygen concentrations at high temperature and typically high flowrate conditions
- steam generator water treatment components are exposed to treated-water (secondary) with low oxygen concentrations at ambient temperature with typically stagnant flow conditions
- main steam, steam drains, and auxiliary steam components are exposed to steam with low oxygen concentrations at high temperature

External Environment

- The SPCS components that require AMR are located in the Containment, other indoor areas of the plant, and outdoor areas of the plant. These components are exposed to an air or atmosphere/weather environment. External surfaces of SPCS components may also be exposed to borated water leakage conditions.

Applicable Aging Effects

In the North Anna and Surry LRAs, Section 3.4, the applicant states that it has reviewed site-specific operating experience and industry-wide experience to support its determination of applicable aging effects for the SPCSs. The applicant identified the following applicable aging effects associated with the materials and environments described above for the SPCS components that are within the scope of license renewal and subject to an AMR:

- cracking of carbon steel, low-alloy steel, and stainless steel components in treated-water, steam, or potentially water-contaminated lubricating oil environments
- cracking of nickel-based alloys in a steam environment, and copper alloys in an air environment
- loss of material from carbon steel, low-alloy steel, and stainless steel components in treated-water, steam, or potentially water-contaminated lubricating oil environment
- loss of material from carbon steel and low-alloy steel components exposed to atmosphere/weather

- loss of material from carbon steel and low-alloy steel components in an air environment
- loss of material from nickel-based alloy in a steam environment and copper alloy components in a treated-water environment
- loss of material from carbon steel and low-alloy steel components resulting from potential borated water leakage onto the external surface of the components

3.7.1.2 Aging Management Programs

In the North Anna and Surry LRAs, in Tables 3.4-1 through 3.4-7, the applicant identified 10 aging management programs used to manage the effects of aging associated with the SCs of SPCS components that are subject to an AMR. These aging management programs and activities include augmented inspection activities, boric acid corrosion surveillance programs, chemistry control program for primary systems, chemistry control program for secondary systems, general-condition-monitoring activities, infrequently accessed area inspection activities, ISI Program - component and component support inspections, secondary piping and component inspections, tank inspection activities, and the work control process. In the North Anna and Surry LRAs, Appendix B, the applicant provides a detailed description of each of the above programs. In addition, the applicant demonstrates each program's effectiveness to manage the applicable aging effects for the period of extended operation.

3.7.2 Staff Evaluation

The staff reviewed the information in the North Anna and Surry LRAs, Sections 2.3.4, and 3.4, and the portions of Appendix B that apply to the SPCS components to determine if the applicant has demonstrated compliance with the requirements of 10 CFR 54.21(a)(3). In addition, the staff reviewed the applicable portions of the NAS and SPS UFSARs, plant and industry (as applicable) operating history, license renewal system drawings provided with each LRA, and other applicable portions of Appendix A, Appendix B, and Appendix C of each LRA. The staff also conducted a telephone conference call with the applicant on October 09, 2001, to discuss the information provided to, and reviewed by, the staff. The information provided by the applicant during that telephone conference is documented and docketed in a letter to the applicant dated October 25, 2001. No request for additional information was needed by the staff to complete its review of the SPCS components.

During its review of the North Anna Unit 1 and 2 and Surry Unit 1 and 2 LRAs, the staff forwarded to the applicant a request for additional information (RAI) that related to non-safety-related (NSR) piping systems which are connected to the safety-related (SR) piping or are in close proximity such that their failure could adversely impact the intended safety function. The RAI (RAI 2.1-3) was sent to the applicant in order to obtain information about this issue and thus ascertain that NSR piping in proximity to SR piping would not adversely affect the safety-related function of systems that are within the scope of license renewal.

In response to this RAI the applicant provided Tables 2.1-3-4 and 2.1-3-5. Table 2.1-3-4 identified the aging management results for systems within the expanded scope of license renewal for North Anna Units 1 and 2. Table 2.1-3-5 identified the aging evaluation results for systems within the expanded scope of license renewal for Surry Units 1 and 2. The applicant also included Table N3.4-8, "Steam and Power Conversion System - Extraction Steam: Additional Criterion 2 (Spatial Orientation) In-Scope Components," to document the fact that the extraction steam system was added to the scope of license renewal as a result of the staff's RAI. The tables documented the results of the applicant's aging management evaluation for materials and aging effects included within the expanded scope and identified the aging management programs that will manage the aging effects during the period of extended operation.

The staff reviewed the information included in Tables 2.1-3-4, 2.1-3-5 and N3.4-8 to ascertain that the expanded scope of license renewal has identified the materials and aging effects and that the proposed aging management programs will manage those aging effects during the period of extended operation. The review revealed that cast iron material was added to the expanded scope of license renewal. Loss of material was identified as the aging effect requiring management for cast iron material during the period of extended operation. The aging management programs that will manage loss of material of cast iron are the boric acid corrosion surveillance programs, the chemistry control programs for primary and secondary systems, general-condition-monitoring activities, infrequently accessed area inspection activities, secondary piping and component inspections, service water systems inspections, and the work control process. These aging management programs have been described in Sections 3.3.1 through 3.3.4 of this SER. Based upon its review of the information included in Tables 3.1-3-4, 2.1-3-5, and N3.4-8, the staff concluded that the applicant has adequately addressed the impact of NSR piping on SR piping in the steam and power conversion systems.

The staff's review and evaluation of the specific scope of SPCS SCs included by the applicant as being within the scope of license renewal and subject to an AMR are provided in Section 2.3.4 of this SER. In addition, the staff's review and evaluation of the different aging management activities credited by the applicant to manage the applicable aging effects of the SPCS systems are provided in Sections 3.3.1 and 3.3.4 of this SER. The staff's review and evaluation of the applicant's AMR for the SPCSs are provided in this section of the SER.

3.7.2.1 Aging Effects

The staff's review verified that the components of the SPCSs are constructed from carbon steel, low-alloy steel, stainless steel, and copper and nickel-based alloys. A review of each LRA, system drawings, the UFSARs, and system documentation confirmed that these components are exposed to outdoor environments, plant spaces, and containment ambient conditions, and are potentially exposed to boric acid water leakage. Internally, the staff reviewer confirmed that the SPCS components are exposed to treated water, steam, and lubricating oil environments.

In Appendix C of the North Anna and Surry LRAs, the applicant describes the methodology it used to perform an AMR and provides a discussion of the potential aging effects based on materials and environments. As part of its methodology, the applicant concluded that aging management is required for any applicable aging effects that can result in the loss of intended functions for any passive or long-lived SC during the period of extended operation. The staff reviewed the applicable information in Appendix C, and determined that it is consistent with the rule and no omissions were identified.

Using the AMR methodology, the applicant identified the aging effects discussed above. In Tables 3.4-1 through 3.4-7 of the North Anna and Surry LRAs, the applicant listed the applicable aging effects associated with the various components, component functions, materials, and environments, and the applicable aging management activities. In Appendix C of its LRAs, the applicant also describes its plant-specific and industry-wide operating experience review to support its identification of applicable aging effects for the SPCSs. The staff reviewed and verified that the material, environmental, and aging effect combinations are consistent with published literature and industry operating experience, and that there is reasonable assurance that all applicable aging effects have been identified.

3.7.2.2 Aging Management Programs

The applicant has identified 10 aging management programs for managing the applicable aging effects of the SPCS SCs. In each LRA, Tables 3.4-1 through 3.4-7, the applicant identified each program and its application(s) to the SCs and the associated aging effects. The applicant states that the programs were developed from industry-wide data, industry-developed methodologies, NRC documents, and the applicant's own experience.

The staff's detailed review of aging management activities performed to manage the applicable aging effects is provided in Sections 3.3.1 and 3.3.4 of this SER. However, as part of its AMR, the staff did verify that the aging management activities applicable to different SPCS SCs were consistent with the applicable aging effects. As a result of this review, the staff verified that the AMAs credited for managing applicable aging effects for SPCS components are consistent with current industry practices. No omissions or concerns as to AMAs used to manage the SPCSs were identified.

3.7.3 Conclusion

On the basis of the review described above, the staff concludes that the applicant has performed an AMR that adequately identifies the applicable aging effects for the SPCS SCs. In combination with the staff's scoping review, as documented in Section 2.3.4 of this SER, and the staff's aging management activities reviews, as documented in Sections 3.3.1 and 3.3.4 of this SER, the staff finds that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

3.8 Aging Management of Structures and Component Supports

3.8.1 Containment

3.8.1.1 Summary of Technical Information in the Application

Section 3.5.1 of each LRA provides the applicant's aging management review of the containment. Table 3.5.1-1 of each LRA summarizes the applicant's aging management review of the containment structural members by providing (1) the passive function, (2) the material group, (3) the environment, (4) the aging effects requiring management, and (5) the specific aging management activities that manage the aging effects.

The materials of construction for the containment structural members, which are subject to aging management review, are (1) concrete, (2) low-alloy steel, (3) stainless steel, and (4) elastomers. The applicant states that the containment has been designed and constructed in accordance with American Concrete Institute (ACI) 318-63, "Building Code Requirements for Structural Concrete." The cement used in the concrete is consistent with specifications of the American Society for Testing and Materials (ASTM) C150 and the aggregates in the concrete mix conform to ASTM C33. Also, the applicant states that it has used the proper arrangement and distribution of reinforcement to control cracking in accordance with ACI 201.2R-67, "Guide to Durable Concrete." Similar concrete materials are used for the grout. In addition, the applicant states that

- testing of the aggregates used in the concrete was performed in accordance with the testing methods identified in ASTM C295 OR ASTM C227
- porous concrete was used under the base mat to provide drainage for the containment structure
- leaching of calcium hydroxide is non-significant for the containment structure since it is not exposed to flowing water

The different environments for the containment structural members are (1) atmosphere/weather, (2) soil, (3) treated-water, (4) raw water, (5) containment air, and (6) the sheltered-air environment inside buildings other than containment. These environments, with the exception of the localized temperatures described below, are as indicated in Table 3.0-2 in each LRA. The applicant states that the air temperature varies throughout the containment according to location and elevation. General air temperatures in some specific cases can be found to be higher than 125°F, but not greater than 150°F. The containment hot pipe penetrations may be subject to elevated localized temperatures, but not greater than 200°F, and these temperatures do not affect the overall integrity of the containment. The applicant states that the containment structural members may also be exposed to groundwater, if they are located below the groundwater elevation. The results of recent groundwater analyses, which are discussed in Appendix C of each LRA, indicate that the groundwater chemistry is non-aggressive at both the North Anna and Surry sites. The fuel transfer tube and its enclosure (including expansion joints) normally are exposed to ambient air; however, when the fuel transfer tube blind flange is removed and the refueling cavity is flooded, the fuel transfer tube is exposed to treated-water (borated water). The temperature of this treated-water is maintained to be less than 140°F. Additionally, systems within the containment contain borated water. Therefore, structural members and penetrations in the containment could be exposed to a borated water leakage environment.

3.8.1.1.1 Aging Effects

In Section 3.5.1 of each LRA, the applicant identified the following applicable aging effects for structural members inside the containment:

- loss of material for carbon steel and low-alloy steel structural members in air or atmosphere/weather environments
- loss of material for stainless steel structural members in treated-water (borated water) or raw water environments
- loss of material for carbon steel and low-alloy steel structural members in a borated water leakage environment
- cracking and change in material properties for elastomers in an air environment

3.8.1.1.2 Aging Management Programs

The applicant credits the following aging management activities with managing the identified aging effects for the structural members of the containment:

- civil engineering structural inspection
- boric acid corrosion surveillance
- chemistry control program for primary systems
- IS program - containment inspection
- general-condition-monitoring activities
- infrequently accessed area inspection activities
- work control process

A description of these aging management activities is provided in Appendix B of each LRA. The applicant concludes that the effects of aging associated with the containment will be adequately managed by these aging management activities such that there is reasonable assurance that the intended functions will be maintained consistent with the current licensing basis during the period of extended operation.

3.8.1.2 Staff Evaluation

In addition to Section 3.5.1 of each LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results - Structures" and the applicable aging management activity descriptions provided in Appendix B of each LRA to determine whether the aging effects for the containment structural members have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.8.1.2.1 Aging Effects

In Section 3.5.1 of each LRA, the applicant provides an aging management review of the containment and interior structural components. The methodology used to perform the aging management review for specific aging effects is described in Appendix C of each LRA. This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management programs credited for the containment structural members at North Anna and Surry. The staff's evaluation includes a review of the aging effects considered and the basis for applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for containment structural members.

The aging effects identified by the applicant that could cause loss of intended functions for the containment structural members are (1) loss of material for carbon steel and low-alloy steel components in air, atmosphere/weather, or borated water leakage environments, (2) loss of material properties for stainless steel structural members in treated or raw water environments, , and (3) change in material properties and cracking of elastomers in an air environment.

Concrete: Appendix C of each LRA lists (1) loss of material, (2) cracking, and (3) change in material properties as plausible aging effects for containment concrete components.

For the loss of material aging effect, the applicant identified the following plausible aging mechanisms: (1) aggressive chemical attack, (2) freeze-thaw, (3) elevated temperatures, and (4) corrosion of embedded steel. The applicant briefly describes each of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.1-1 of each LRA does not list loss of material as an aging effect requiring management for any of the concrete structural members located in either air or soil environments.

For the cracking aging effect, the applicant identified the following plausible aging mechanisms: (1) settlement, (2) freeze-thaw, (3) aggressive chemical attack, (4) alkali-aggregate reaction, (5) corrosion of embedded steel, and (6) elevated temperatures. The applicant briefly describes each of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.1-1 of each LRA does not list cracking as an aging effect requiring management for any of the concrete structural members located in either air or soil environments.

For the change in material properties aging effect, the applicant identified the following plausible aging mechanisms: (1) aggressive chemical attack, (2) alkali-aggregate reaction, (3) elevated temperatures, and (4) leaching of calcium hydroxide. The applicant briefly describes each of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.1-1 of each LRA does not list change in material properties as an aging effect requiring management for any of the concrete structural members located in either air or soil environments.

The staff considers each of the above aging effects (loss of material, cracking, and change in material properties) to be both plausible and applicable for containment concrete and containment interior concrete components. Industry experience indicates that age-related degradation of concrete structures has occurred at a number of plants, demonstrating the need for aging management of concrete nuclear structures. As such, in RAIs 3.5-3 and 3.5-7 the staff requested that the applicant identify the aging management program that will be used to manage the aging effects for containment concrete and containment interior concrete components. In response, the applicant stated that its aging management review for the containment concludes that there are no aging effects requiring management for concrete structural members. However, based on discussions with the NRC staff and the staff's position on concrete aging discussed in a letter to Florida Power and Light dated October 30, 2001, the applicant committed to credit the examinations specified by ASME Section XI, Subsection IWL, Examination Category L-A to manage the potential aging effects of concrete structural members of the containment. The applicant stated that these examinations will be added to the ISI Program - Containment Inspections aging management activity, which is covered in Section B2.2.12 of each LRA. For the containment internal concrete components, the applicant stated that it will use the Civil Engineering Structural Inspection aging management activity to manage the potential aging effects. The Civil Engineering Structural Inspection aging management activity is covered in Section B2.2.6 of each LRA. Once incorporated, as committed in this response, the staff considers this issue to be resolved.

The staff also considers each of the above aging effects (loss of material, cracking, and change in material properties) to be plausible for containment concrete located below groundwater elevation. In Section 3.5.1 of each LRA, the applicant indicates that the containment concrete structural members located below the local groundwater elevation are not exposed to aggressive chemicals on the basis of recent chemical analyses of the groundwater, which is described in Appendix C of each LRA. For both North Anna and Surry, groundwater samples taken over the past 5 to 8 years indicate that the chloride and sulfate concentrations are well below the threshold values for aggressive chemical attack. In addition, the pH level of the groundwater samples is well above the threshold (pH < 5.5) for aggressive chemical attack. Consequently, the staff concludes that the aging effects such as loss of material, cracking, and change in material properties due to aggressive chemical attack are not expected to be significant for below grade exterior concrete regions.

In addition, loss of material and cracking due to corrosion of embedded steel, is not expected to be significant for below grade exterior concrete regions. The applicant, however, did not provide a technical basis for ensuring that the groundwater remains non-aggressive during the period of extended operation. In RAI 3.5-2, the staff requested that the applicant to indicate what method (e.g., periodic monitoring of groundwater chemistry) will be used to ensure that the groundwater remains non-aggressive during the period of extended operation. In response, the applicant stated that there is currently not enough historical groundwater sampling data available to develop a groundwater chemistry trend. Although the applicant does not expect the groundwater at either North Anna or Surry to become aggressive, routine monitoring of the groundwater chemistry at both sites is presently being conducted and will be conducted on an annual basis during the period of extended operation. In addition, the applicant has committed to monitor the groundwater chemistry at a different time each year so that any seasonal variations in the groundwater chemistry may be detected. Monitoring of groundwater chemistry will be performed as part of the applicant's Civil Engineering Structural Inspection aging management activity. In its letter dated July 25, 2002, the applicant stated that the UFSAR Supplement Section 18.2.6, "Civil Engineering Structural Inspections" has been modified to include annual monitoring of groundwater chemistry. Additionally, Section 18.2.6 specifies that groundwater chemistry should be considered as part of engineering evaluations of inspection results. Since the applicant has completed this action, the staff considers confirmatory action 3.8.1-1 closed.

Section 3.5.1 of each LRA states that porous concrete is used under the base mat to provide drainage for the containment structure, and that the use of Type II, low-alkali, portland cement (not calcium aluminate cement) in the porous concrete prevents any erosion from concrete and minimizes cracking due to settlement. This issue has been discussed in Information Notice (IN) 98-26, which proposes a structure monitoring program to manage this aging effect. In addition, if a de-watering system is relied upon for control of erosion of cement from porous concrete subfoundations and/or relied on to control settlement, then proper functioning of the de-watering system must be ensured through the period of extended operation. In RAI 3.5-1, the staff requested that the applicant provide justification for not including an aging management review of the de-watering system for control of hydrostatic pressure to the containment liner plate. Furthermore, if a de-watering system is relied on for control of hydrostatic pressure, then the de-watering system needs to be included within the scope of license renewal and subject to an aging management review. In response, the applicant stated that,

> The foundation mats of the Surry and North Anna Containments are located below the ground water table. The below-grade foundation and exterior wall design includes a waterproof membrane and high-density, low-permeability concrete that significantly reduces the likelihood of groundwater migration to the Containment liner. Therefore, the occurrence of hydrostatic pressure on the Containment liner due to groundwater is unlikely. In addition to design features, a non-safety related Containment subsurface drainage system was installed to further reduce the potential for hydrostatic pressure on the liner.
>
> The subsurface drainage system was originally determined not to be within the scope of license renewal. However, further review has determined, in consideration of the importance of the Containment liner, that the drainage system will be conservatively included within the scope of license renewal to ensure its operability through the extended period of operation.
>
> An aging management review has been completed for the subsurface drainage system components, the associated component supports, and the associated concrete access shafts. The pump casings, valve bodies and piping associated with the system are subject to loss of material and will be managed by the Work Control Process activity described in Section B2.2.19 of the applications. Component supports are subject to loss of material, and will be managed by the Infrequently Accessed Area Inspection activity described in Section B2.1.2. Although the aging management review has concluded that there are no aging effects requiring management for the concrete access shafts, the potential aging effects of loss of material, cracking, and change in material properties will be managed, as discussed In its response to RAI 3.5-7, with the Infrequently Accessed Areas Inspection activity.

In its letter dated July 25, 2002, the applicant stated that the subsurface drainage systems around the containments have been incorporated into the license renewal scope for both Surry and North Anna. The UFSAR Supplement Section 18.1.2, "Infrequent Accessed Area Inspection Activities," has been modified to include the structures associated with these systems. The UFSAR Supplement Section 18.2.19, "Work Control Process" encompasses the mechanical portions of the system. Since the applicant has completed this action, the staff considers confirmatory action 3.8.1-2 closed.

Steel: Appendix C of each LRA lists loss of material and cracking as plausible aging effects for containment steel structural members.

For the loss of material aging effect, the applicant identified the following plausible aging mechanisms: (1) corrosion, (2) wear, (3) boric acid wastage, and (4) fretting. The applicant briefly describes each of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.1-1 of each LRA identifies loss of material for carbon and low-alloy steel structural members in air, atmosphere/weather, and borated water leakage environments as an aging effect requiring management.

For the cracking aging effect, the applicant identified the following plausible aging mechanisms: (1) stress-corrosion cracking and (2) flaw initiation and growth. The applicant briefly describes each of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.1-1 of each LRA does not list cracking as an aging effect requiring management for any of the containment steel structural members.

In a letter dated May 22, 2002 (Serial No. 02-277), the staff requested that the applicant provide the technical basis for not considering the following aging effects for containment steel components:

- loss of material due to corrosion in inaccessible areas (e.g. embedded containment steel liner) where examination of accessible areas may not be indicative of degradation in inaccessible areas
- cracking of steel due to stress-corrosion cracking and flaw initiation and growth
- reduction in fracture toughness due to neutron embrittlement

For loss of material due to corrosion in inaccessible areas, the applicant stated that inaccessible areas, such as embedded containment steel liner, were included in an AMR (refer to Table 3.5.1-1), and is managed by the containment ISI Program (IWE) and the 10 CFR Part 50, Appendix B, corrective action program. In addition, the applicant recently excavated portions of the Surry Unit 1 containment floor to inspect and verify that aging was not occurring in the inaccessible area of the interior liner plate. On the basis of more than 30 years of operating history and the inspection finding, the applicant believes that, if operating conditions remain the same, there is reasonable assurance that aging will not occur. If operating condition change, the applicant would be obligated to reassess the potential for aging to the inaccessible areas as part of its 10 CFR Part 50, Appendix B, corrective actions that apply to any failures that may occur in containment. In addition, if IWE inspections reveal findings associated with the accessible containment liner wall, the applicant again would be obligated to reassess the potential effects to the inaccessible areas as part of its 10 CFR Part 50, Appendix B, corrective actions that apply to these AMAs. For the exterior inaccessible liner plate wall, the applicant has committed to periodic monitoring of the groundwater in its response to RAI 3.5-2. The staff found the applicant's response to be adequate.

For cracking of steel due to stress-corrosion cracking, and flaw initiation and growth, the applicant explained that flaw initiation and growth are limited to Class 1 piping components and do not apply to any stainless steel structural components. For stress corrosion cracking, the stainless-steel structural components of concern in the containment are the fuel transfer tube, refueling cavity liner and electrical penetrations. With regard to the stainless steel transfer tube and refueling cavity liner, temperatures are maintained below 140°F, as required by the applicant's technical specification, eliminating the potential for stress-corrosion cracking. With regard to the stainless steel electrical penetration, these components are in an air environment, which also eliminates the potential for stress-corrosion cracking. The staff found the applicant's response to be adequate.

For reduction in fracture toughness due to neutron embrittlement, the applicant stated that the only component with sufficient neutron fluence for embrittlement to be a potential concern is the neutron shield tank, which is evaluated in the AMR for the NSSS supports. The staff acknowledged the applicant's response, and evaluated this aging effect in its review of NSSS supports (LRA Section 3.5.9).

The staff found the applicant's approach for evaluating the applicable aging effects for the containment structural steel components to be reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effects for containment structural steel components.

Elastomers: Appendix C of each LRA lists (1) cracking, (2) reduction in fracture toughness and (3) change in material properties as plausible aging effects for containment elastomer components.

For the cracking aging effect, the applicant identified the following plausible aging mechanisms: (1) irradiation, (2) thermal exposure, and (3) ultraviolet radiation and ozone. The applicant briefly describes each of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.1-1 of each LRA identifies cracking of elastomers in an air environment as an aging effect requiring management.

For the reduction in fracture toughness aging effect, the applicant identified neutron embrittlement as a plausible aging mechanism. The applicant briefly describes neutron embrittlement in Appendix C of each LRA and states that this aging mechanism was evaluated during the aging management reviews. Table 3.5.1-1 of each LRA does not list reduction in fracture toughness as aging effect requiring management for any of the elastomer components in the containment.

For the change in material properties aging effect, the applicant identified (1) irradiation and (2) thermal exposure as plausible aging mechanisms. The applicant briefly describes each of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.1-1 of each LRA identifies change in material properties of elastomers in an air environment as an aging effect requiring management.

The staff found the applicant's approach for evaluating the applicable aging effects for the containment elastomer components to be reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effects for containment elastomer components.

3.8.1.2.2 Aging Management Programs

The aging management activities used by the applicant to manage the above aging effects are the Civil Engineering Structural Inspection, Boric Acid Corrosion Surveillance, Chemistry Control Program for Primary Systems, ISI Program - Containment Inspection, General-condition-monitoring activities, Infrequently Accessed Area Inspection Activities, and Work

Control Process. Within a given category of structural members, the aging management utilized by the applicant depends on the environment. For example, for access doors, the General-condition-monitoring activities AMA is used for doors in an air environment, while the Boric Acid Corrosion Surveillance AMA is used for doors that may be exposed to a borated water leakage environment. This breakdown is defined for each containment structural member in Table 3.5.1-1 of each LRA. A complete evaluation of the above aging management activities is found in Sections 3.3.1 and 3.3.4 of this SER. In this section, the staff reviewed the applicability of the above aging management activities to the containment structural members. The staff has identified the following issues related to the ISI Program - Containment Inspection aging management activity.

The scope of Subsection IWE inspections included in the ISI Program - Containment Inspection aging management activity is identified in LRA Section B2.2.12 as Categories E-A (containment surfaces), E-C (containment surfaces requiring augmented inspections), E-G (pressure-retaining bolting, and E-P (all pressure-retaining components). Categories E-B and E-F are identified as being optional in accordance with 10 CFR 50.55a(b)(2)(ix)(C). However, Category E-D (seals, gaskets, and moisture barriers) is not identified within the scope of this aging management activity. In RAI 3.5.4, the staff requested that the applicant explain why this category is not included within the scope of the ISI Program - Containment Inspection AMA. In response, the applicant stated that it uses the Work Control Process AMA to manage the aging of containment seals and gaskets since that activity involves more thorough and more frequent inspection of the seals and gaskets than do inservice inspections, which are required only once per 10-year interval. Table 3.5.1-1 of each LRA confirms the use of the Work Control Process to manage aging effects for seals and gaskets (identified as O-rings in the table). Regarding moisture barriers, there are no such barriers that are within the scope of ISI-IWE, Category E-D inspections incorporated into the design of the containment structures for Surry or North Anna. The staff considers the applicant's response to be acceptable.

The ISI Program - Containment Inspection aging management activity also includes Category E-P (all pressure-retaining components), which refers to 10 CFR Part 50, Appendix J, Option B. However, there is no description of the 10 CFR Part 50, Appendix J leak rate testing activity as an aging management program. It is not clear whether the applicant is crediting the complete requirements of 10 CFR Part 50, Appendix J as part of the ISI Program - Containment Inspection. In RAI 3.5-5, the staff requested that the applicant describe the scope of the 10 CFR Part 50, Appendix J program that is being credited for license renewal. In response, the applicant stated that containment leak rate testing is performed as required by Surry Technical Specification 4.4 (Containment Tests) and North Anna Technical Specification 3.6.1.2 (Containment Leakage). These technical specifications invoke the testing requirements of 10 CFR Part 50, Appendix J, Option B. Containment leak rate testing, in accordance with the ISI Program - Containment Inspection AMA described in Section B2.2.12 of the application, is credited with managing the aging of containment pressure-retaining components. The applicant also stated that compliance with identified testing requirements and acceptance standards confirms that the management of aging effects for sealing surfaces is effective to ensure the integrity of the containment pressure boundary. The staff found the applicant's response to RAI 3.5-5 to be acceptable.

On the basis of the information discussed above and the review of the aging management activities in Sections 3.3.1 and 3.3.4 of this SER, the staff concludes that the applicant has demonstrated that the aging effects for containment structural members will be adequately managed during the period of extended operation.

3.8.1.3 Conclusions

The staff has reviewed the information in Section 3.5.1 of each LRA and the applicable aging management activity descriptions in Appendix B of each LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the containment structural members will be adequately managed so that there is reasonable assurance that these structural components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.8.2 Other Structures

3.8.2.1 Summary of Technical Information in the Application

Sections 3.5.2 through 3.5.8 of each LRA provides the applicant's aging management review of several structures outside containment. The structures covered in Sections 3.5.2 through 3.5.8 of each LRA are listed below:

- auxiliary building structure - North Anna (auxiliary building, cable vault, cable tunnel, pipe tunnel, hydrogen recombiner vault, rod drive room)
- auxiliary building structure - Surry (auxiliary building, cable vault, cable tunnel, pipe tunnel, motor control center room)
- other class I structures - North Anna (safeguards building; main steam valve house; quench spray pump house; fuel oil pump house; auxiliary feedwater pump house and tunnel; casing cooling pump house; and service water pump house, pipe expansion joint enclosure, valve house, and tie-in vault)
- other class I structures - Surry (safeguards building, main steam valve house, containment spray pump building, fuel oil pump house, fire pump house)
- fuel building
- miscellaneous structures - North Anna (turbine building, service building, station blackout building, security diesel building, maintenance building)
- miscellaneous structures - Surry (turbine building, service building, station blackout building, security diesel building, black battery building, condensate polishing building, radwaste facility)
- intake structures - North Anna (intake structure, discharge tunnels and seal pit)
- intake structures - Surry (low-level intake structure, high-level intake structure, concrete circulating water pipe, discharge tunnel and seal pit)
- yard structures - North Anna (tank foundations and missile barriers, manholes, fuel oil storage tank dike, transformer firewalls/dikes, duct banks, security lighting poles, domestic water treatment building, auxiliary service water expansion joint enclosure, yard valve pit, containment mat sub-surface pump access shaft)
- yard structures - Surry (tank foundations and missile barriers, manholes, fuel oil storage tank dike, transformer firewalls/dikes, duct banks, security lighting poles, containment mat sub-surface pump access shaft)
- earthen structures - North Anna (service water reservoir, floodwall west of the turbine building)
- earthen structures - Surry (intake canal, discharge canal)

The structural members for each of these structures are listed in Tables 3.5.2 through 3.5.8 of each LRA. Each of these tables summarizes the applicant's aging management review of the structural members by providing (1) the passive function, (2) the material group, (3) the environment, (4) the aging effects requiring management, and (5) the specific aging management activities that manage the aging effects.

The different materials of construction and environments for the structural members contained in the structures listed in Tables 3.5.2 through 3.5.8 of each LRA are given below:

Structure	Materials	Environments
Auxiliary Building Structure	concrete, carbon steel, low-alloy steel	atmosphere/weather, sheltered-air, soil, borated water leakage
Other Class I Structures - North Anna	concrete, carbon steel, low-alloy steel	atmosphere/weather, sheltered-air, soil, borated water leakage, raw water
Other Class I Structures - Surry	concrete, carbon steel, low-alloy steel	atmosphere/weather, sheltered-air, soil, borated water leakage
Fuel Building	concrete, carbon steel, low-alloy steel, stainless steel	atmosphere/weather, sheltered-air, soil, borated water leakage, treated-water
Miscellaneous Structures - North Anna	concrete, carbon steel, low-alloy steel, stainless steel, aluminum	atmosphere/weather, sheltered-air, soil
Miscellaneous Structures - Surry	concrete, carbon steel, low-alloy steel, stainless steel, aluminum, elastomers	atmosphere/weather, sheltered-air, soil
Intake Structures - North Anna	concrete, carbon steel, low-alloy steel, aluminum	atmosphere/weather, sheltered-air, soil, raw water (brackish)
Intake Structures - Surry	concrete, carbon steel, low-alloy steel, rubber	atmosphere/weather, sheltered-air, soil, raw water (brackish)
Yard Structures - North Anna	concrete, carbon steel, low-alloy steel, galvanized steel	atmosphere/weather, sheltered-air, soil
Yard Structures - Surry	concrete, carbon steel, low-alloy steel	atmosphere/weather, sheltered-air, soil

Earthen Structures - North Anna	concrete, soil, carbon steel	atmosphere weather, raw water, soil
Earthen Structures - Surry	concrete, soil, rubber, polysulfide sealant	atmosphere weather, raw water, soil

External service environments for air, atmosphere/weather, borated water leakage, and soil are specified in Table 3.0-2 in each LRA. Deviations from the environments described in Table 3.0-2 for the structures outside containment in each LRA are as follows:

- maximum temperature in upper level of main steam valve house for North Anna is 160°F (LRA Section 3.5.3 - Other Class 1 Structures)
- maximum temperature in upper level of main steam valve house for Surry is 140°F (LRA Section 3.5.3 - Other Class 1 Structures)
- minimum temperature in the emergency diesel generator room is 20°F (LRA Section 3.5.5 - Miscellaneous Structures)

3.8.2.1.1 Aging Effects

The applicable aging effects, as determined by the applicant, for different material/environment combinations for the structural members listed in Tables 3.5.2 through 3.5.8 of each LRA are given below. For the Auxiliary Building Structure (LRAs Section 3.5.2), the aging effects requiring management are:

- cracking of masonry block walls in an air environment
- loss of material from carbon steel and low-alloy steel in air, atmosphere/weather, or borated water leakage environments

For Other Class I Structures (LRAs Section 3.5.3), the aging effects requiring management are:

- loss of material from carbon steel and low-alloy steel in air, atmosphere/weather, or borated water leakage environments
- cracking of masonry block walls in an air environment (NAS 1/2)
- cracking of concrete in soil (NAS 1/2)

For the Fuel Building (LRAs Section 3.5.4), the aging effects requiring management are:

- cracking of masonry block walls in an air environment
- loss of material from carbon steel and low-alloy steel in air, atmosphere/weather, or borated water leakage environments
- loss of material from stainless steel structural members in the treated-water (borated water) environment of the spent fuel pool

For the Miscellaneous Structures (LRAs Section 3.5.5), the aging effects requiring management are:

- cracking of masonry block walls in an air environment
- loss of material from carbon steel and low-alloy steel in an air environment

- cracking and change in material properties of elastomers in an air environment (Surry)

For the Intake Structures (LRAs Section 3.5.6), the aging effects requiring management are:

- cracking of concrete in an air or atmosphere/weather environments
- loss of material from carbon steel and low-alloy steel structural members in air or atmosphere/weather environments
- loss of material from carbon steel and low-alloy steel structural members in a raw water environment (NAS 1/2)
- change in material properties of concrete in raw water (brackish) or atmosphere/weather environments (SPS 1/2)
- cracking of concrete in a raw water (brackish) environment (SPS 1/2)
- loss of material from concrete in a raw water (brackish) environment (SPS 1/2)
- change in material properties and cracking of elastomers in an air environment (SPS 1/2)
- loss of material from carbon steel and low-alloy steel structural members in a raw water (brackish) environment (SPS 1/2)
- loss of material from concrete in an atmosphere/weather environment (SPS 1/2)

For the Yard Structures (LRA Section 3.5.7), the aging effects requiring management are:

- loss of material from carbon steel and low-alloy steel structural members in air or atmosphere/weather environments
- cracking of concrete in an atmosphere/weather environment
- loss of material from concrete in an atmosphere/weather environment (NAS 1/2)
- loss of material from galvanized steel structural members in an atmosphere/weather environment (NAS 1/2)
- change in material properties of concrete in air, soil, or atmosphere/weather environments (SPS 1/2)
- cracking of concrete in air or soil environments (SPS 1/2)

For the Earthen Structures (LRA Section 3.5.8), the aging effects requiring management are:

- loss of material and loss of form of soil in an atmosphere/weather environment
- loss of material from carbon and low-alloy steel in a soil environment (NAS 1/2)
- loss of material and loss of form of soil in a raw water environment (SPS 1/2)
- change in material properties of concrete in a raw water (brackish) environment (SPS 1/2)
- cracking of concrete in raw water (brackish) or atmosphere/weather environments (SPS 1/2)
- loss of material from concrete in raw water (brackish) or atmosphere/weather environments (SPS 1/2)
- cracking and change in material properties of the elastomers exposed to an atmosphere/weather environment (SPS 1/2)

3.8.2.1.2 Aging Management Programs

The applicant credits the following aging management activities with managing the identified aging effects for the structural members listed in Tables 3.5.2 through 3.5.8 of each LRA:

- civil engineering structural inspection
- chemistry control program for primary systems
- buried piping and valve inspection activities
- general-condition-monitoring activities
- infrequently accessed area inspection activities
- work control process

A description of these aging management activities is provided in Appendix B of each LRA. The applicant concludes that the effects of aging associated with the structural members listed in Tables 3.5.2 through 3.5.8 of each LRA will be adequately managed by these aging management activities such that there is reasonable assurance that the intended functions will be maintained consistent with the current licensing basis during the period of extended operation.

3.8.2.2 Staff Evaluation

In addition to Sections 3.5.2 through 3.5.8 of each LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results - Structures," and the applicable aging management activity descriptions provided in Appendix B of each LRA to determine whether the aging effects for the various structural members in LRA Sections 3.5.2 to 3.5.8 have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.8.2.2.1 Aging Effects

In Section 3.5.2 through 3.5.8 of each LRA, the applicant provides an aging management review of several structures outside containment. The methodology used to perform the aging management review for specific aging effects is described in Appendix C of each LRA. This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management programs credited for the structures outside containment at North Anna and Surry. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the structures outside containment.

Concrete: Appendix C of each LRA lists (1) loss of material, (2) cracking, and (3) change in material properties as plausible aging effects for concrete components.

For the loss of material aging effect, the applicant identified the following plausible aging mechanisms: (1) aggressive chemical attack, (2) freeze-thaw, (3) elevated temperatures, and (4) corrosion of embedded steel, (5) abrasive erosion and cavitation. The applicant briefly describes each of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Tables 3.5.2 through 3.5.8 of each LRA identify loss of material as an aging effect requiring management for some concrete components in a raw water (brackish) and atmosphere/weather environments. A list of the structures that identify loss of material as an applicable aging effect for their concrete components is provided in Section 3.8.2.1.1 of this SER.

For the cracking aging effect of concrete components, the applicant identified the following plausible aging mechanisms: (1) settlement, (2) freeze-thaw, (3) aggressive chemical attack, (4) alkali-aggregate reaction, (5) corrosion of embedded steel, and (6) elevated temperatures. The applicant briefly describes each of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Tables 3.5.2 through 3.5.8 of each LRA identify cracking as an aging effect requiring management for some concrete components in soil, air, atmosphere/weather, and raw water (brackish) environments. A list of the structures that identify cracking as an applicable aging effect for their concrete components is provided in Section 3.8.2.1.1 of this SER.

For the cracking aging effect of masonry block walls, the applicant identified the following plausible aging mechanisms: (1) dry shrinkage, (2) expansion/contraction, (3) improper joint isolation, and (4) poor mortar durability. The applicant briefly describes each of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Tables 3.5.2 through 3.5.8 of each LRA identify cracking as an aging effect requiring management for masonry block walls in an air environment. A list of the structures that identify cracking as an applicable aging effect for masonry block walls is provided in Section 3.8.2.1.1 of this SER.

For the change in material properties aging effect, the applicant identified the following plausible aging mechanisms: (1) aggressive chemical attack, (2) alkali-aggregate reaction, (3) elevated temperatures, and (4) leaching of calcium hydroxide. The applicant briefly describes each of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.2 through 3.5.8 of each LRA identify change in material properties as an aging effect requiring management for the air, atmosphere/weather, soil, and raw water (brackish) environments. A list of the structures that identify change in material properties as an applicable aging effect for their concrete components is provided in Section 3.8.2.1.1 of this SER.

The staff considers each of the above aging effects (loss of material, cracking, and change in material properties) to be both plausible and applicable for concrete components, including masonry block walls, in all of the environments listed by the applicant. Industry experience indicates that age-related degradation of concrete structures has occurred at a number of plants, demonstrating the need for aging management of concrete nuclear structures. As such, in RAI 3.5-7 the staff requested that the applicant identify the aging management program that will be used to manage the aging effects for concrete components. In initial discussions with the applicant on this issue, the applicant proposed to use any observed aging of the containment concrete structural components, through its ISI Program - Containment Inspection AMA, as an indicator for the aging of concrete components outside containment. The staff stated in RAI 3.5-7 that this approach was unacceptable since an extrapolation of the structural aging of the containment structure to other structures outside containment cannot be assumed. In response to RAI 3.5-7, the applicant stated that there are certain specific concrete structures or concrete structural members for which the applicant has identified aging effects requiring management. For these structures, an aging management activity has been identified in the applications to manage the effects of aging. However, the applicant stated that for the majority of the concrete structures within the scope of license renewal, they have concluded that there are no aging effects requiring management. However, based on discussions with the NRC staff and the staff's position on concrete aging discussed in a letter to Florida Power and Light dated October 30, 2001, the applicant committed to credit its Civil Engineering Structural Inspection

AMA to manage the potential aging effects of all in-scope concrete components in structures outside containment. The applicant states that these examinations will be added to the Civil Engineering Structural Inspection AMA and Infrequently Accessed Area Inspection Activity AMA, which are covered in Sections B2.2.6 and B2.1.2, respectively, in each LRA. As noted earlier in Section 3.5.1.2.1 for the containment internal concrete components, the applicant stated that it would also use the Civil Engineering Structural Inspection AMA to manage the potential aging effects. Once incorporated, as committed in this response, the staff considers this issue to be resolved.

Steel: Appendix C of each LRA lists loss of material and cracking as plausible aging effects for carbon, low-alloy, galvanized, and stainless steel components.

For the loss of material aging effect, the applicant identified corrosion and boric acid wastage as plausible aging mechanisms for steel components in structures outside containment. The applicant briefly describes both of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Tables 3.5.2 through 3.5.8 of each LRA, identify loss of material as an aging effect requiring management for each of the carbon steel or low-alloy steel components in either air, atmosphere/weather, raw water (brackish), borated water leakage, and soil environments. The applicant also identifies loss of material as an applicable aging effect for stainless steel structural members in the treated-water (borated water) environment of the spent fuel pool and for galvanized steel structural members in an atmosphere/weather environment. A list of the structures that identify loss of material as an applicable aging effect for their steel components is provided in Section 3.8.2.1.1 of this SER.

For the cracking aging effect, the applicant identified stress corrosion cracking (SCC) as a plausible aging mechanism for the stainless steel structural members in a borated water environment in the fuel building. The applicant briefly describes SCC in Appendix C of each LRA and states that SCC was evaluated during the aging management reviews. The staff considers SCC to be a plausible aging effect for stainless steel in borated water and requested that the applicant provide a technical basis for excluding cracking of stainless steel as an aging effect requiring management. In its response, in a letter dated May 22, 2002 (Serial No. 02-277), the applicant stated that the potential for SCC is eliminated since temperatures are maintained below 140°F, as required by the applicant's technical specifications. The staff found the applicant's response to be acceptable.

The staff found the applicant's approach for evaluating the applicable aging effects for the steel components in structures outside containment to be reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effects for steel components in structures outside containment.

Aluminum: Only a few of the in-scope components in structures outside containment are made of aluminum. This includes the control room ceiling and louvers roof in both the North Anna and Surry service buildings. In addition, the fire pump house roof access cover in the North Anna intake structure is made of aluminum. The applicant does not identify any aging effects for aluminum and the staff concurs with this finding.

Elastomers: Appendix C of each LRA lists cracking and change in material properties as plausible aging effects for elastomer materials used in structures outside containment.

For the cracking aging effect, the applicant identified thermal exposure and ultraviolet radiation as plausible aging mechanisms for elastomer materials in structures outside containment. The applicant briefly describes both of the above aging mechanisms in Appendix C of each LRA and states that these aging mechanisms were evaluated during the aging management reviews. Tables 3.5.5, 3.5.6 and 3.5.8 of each LRA identify cracking as an aging effect requiring management for elastomers in an air environment.

For the change in material properties aging effect, the applicant identified thermal exposure as a plausible aging mechanism for elastomer materials in structures outside containment. The applicant briefly describes thermal exposure in Appendix C of each LRA and states that this mechanism was evaluated during the aging management reviews. Tables 3.5.5, 3.5.6 and 3.5.8 of each LRA identify change in material properties as an aging effect requiring management for elastomers in an air environment.

The staff concurs with the above conclusions for North Anna and Surry, except it is not clear why the change in material properties and cracking of elastomers is limited to an air environment. Rubber material is used in the circulating water pipe at Surry as a concrete pipe joint gasket. The circulating water in the pipe is a raw water (brackish) environment. In RAI 3.5.6-3, the staff requested the applicant to provide the technical basis for determining that aging effects for elastomers are limited to an air environment. In response, the applicant stated that they performed an aging management review of the circulating water pipe rubber gaskets and the concrete culvert rubber gaskets in a raw water environment. Exposure to ultraviolet radiation, ozone, and temperatures exceeding 95°F (thermal exposure) are considered to be the only aging mechanisms that can result in the aging effects for rubber in a raw water environment. The conclusion of the aging management review indicates that there are no aging effects on these rubber gaskets in a raw water environment because these gaskets are not exposed to ultraviolet radiation, ozone, or temperatures exceeding 95°F. Additionally, a review of technical literature, and site and industry operating experience, has not identified any concerns related to aging of rubber in these applications. Therefore, there are no aging effects requiring management for these rubber gaskets in a raw water environment. The staff found the applicant's response to be acceptable based on the applicant's aging management review.

The staff found the applicant's approach for evaluating the applicable aging effects for the elastomer material components in structures outside containment to be reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effects for elastomers in structures outside containment.

Soil: Appendix C of each LRA lists loss of material and loss of form as plausible aging effects for the soil used in the earthen structures at North Anna and Surry.

For the loss of material aging effect, the applicant identified the following plausible aging mechanisms: (1) erosion, (2) subsurface flow (seepage), (3) rain impact, (4) surface flow, (5) wave action and (6) wind erosion. The applicant briefly describes each of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.8 of each LRA identifies loss of material as an aging effect requiring management for the soil found in atmosphere/weather (North Anna and Surry) or raw water (SPS 1/2) environments and used in the earthen structures.

For the loss of form aging effect, the applicant identified the following plausible aging mechanisms: (1) frost action, (2) sedimentation, (3) settlement, (4) subsurface flow (seepage), and (5) surface flow. The applicant briefly describes each of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.8 of each LRA identifies loss of form as an aging effect requiring management for the soil found in atmosphere/weather (North Anna and Surry) or raw water (SPS 1/2) environments and used in the earthen structures.

The staff found that Section 3.5.8 of the North Anna LRA does not provide information to explain why the aging effects loss of material and loss of form of soil in a raw water environment do not require aging management. Loss of material and loss of form may occur to the soil due to the various aging mechanisms described above (e.g., erosion, sedimentation, subsurface flow, etc.). In RAI 3.5.8-2, the staff requested the applicant to provide the technical basis why loss of material and loss of form of the soil in a raw water environment are not included as aging effects requiring management for the North Anna Earthen Structures. In response, the applicant stated,

> The earthen structure exposed to a raw water environment, as described in the North Anna application, Section 3.5.8, is the Service Water Reservoir (SWR). The SWR embankment dike consists of a wide core of compacted random fill, fine and coarse filters, and a wide outside zone of compacted rockfill. The core is protected on the upstream side by a select fill (2-foot clay liner with a permeability of 1×10^{-6} cm/sec) and on the downstream side by the fine and course filters that extend beneath the compacted rockfill. The clay liner on the upstream slopes is protected with a layer of dumped rockfill.
>
> The entire bottom of the SWR is lined with the same 2-foot clay liner that protects the core of the embankment dike. The insitu material (saprolite) in the bottom of the SWR, below the clay liner, is estimated to have the same permeability (1×10^{-6} cm/sec) as the clay liner. Although the insitu material was not installed and compacted to the same standards of the clay liner, its low permeability further reduces the seepage of water from the bottom of the SWR.
>
> Loss of material from the SWR embankment dike in a raw water environment could occur from wave action. However, the clay liner on the waterside slope of the dike embankment is protected from loss of material due to wave action by a 2-foot layer of dumped rockfill.
>
> The clay liner that is installed on the bottom of the SWR could experience loss of material and loss of form in a raw water environment from the following two conditions:
>
> - flow of water over the surface of the liner in the area of the service water pump house (SWPH) service water intake
> - flow of water over the surface of the liner as a result of the operation of the winter bypass headers at the service water valve house (SWVH)

Tests performed at Massachusetts Institute of Technology (MIT) on the clay liner material from the North Anna SWR indicate that flow rates greater than 0.55 fps are necessary to initiate erosion of the liner. A concrete liner, which has been designed and installed around the intake to the SWPH, reduces the maximum flow rate expected across the impervious clay liner to 0.20 fps.

The clay liner could experience loss of material and loss of form as a result of the operation of the underwater bypass headers at the SWVH. However, the winter bypass system is designed so that exit velocities are minimized. A coarse aggregate erosion apron, which has been placed on the reservoir bottom in the vicinity of the bypass piping discharge, is sized to ensure that velocities over the clay liner are less than 0.55 fps.

Loss of material and loss of form of the SWR embankment dike in a raw water environment could occur from subsurface flow. Subsurface flow (seepage) is the process by which excess ground water moves from the soil mass and exits to the closest available drainage path. Seepage is generally a problem during the initial filling of a reservoir or water control structure. Seepage may lead to the migration of soil fines out of the soil mass. This phenomenon is known as piping. The following techniques have been incorporated into the SWR embankment dike to prevent piping:

- construction of the impervious lining of the dike with materials that, by their nature, have a high resistance to piping
- the introduction, into the downstream portion of the dike, of filters that form a transition in gradation
- stringent requirements for uniformly compacted embankments, with emphasis on control of water content and density during construction

Another source of piping-type failures is along conduits built into or under an embankment. Such a failure is not possible at the SWR because all service water system piping is above the normal saturation level within the core section of the embankment.

The SWR could experience a loss of form from a sedimentation buildup, which could limit the storage capacity required for emergency cooling. However, sedimentation or sludge depth of up to 4 feet can be tolerated without impacting the thermal performance of the 30-day cooling water inventory of the SWR. After twenty years of operation, only 1 foot of sludge-buildup has occurred in the SWR. Therefore, sludge-buildup will not result in loss of form for the period of extended operation.

Because of the protective measures that have been provided in the design and construction of the SWR, loss of material and loss of form of soil exposed to raw water environment is not aging effects that require aging management.

Additionally, a review has determined that there is no North Anna operating experience to support a concern for loss of material or loss of form of soil in Earthen Structures exposed to a raw water environment.

In the SER with open items issued in June 2002, the staff found the applicant's response to RAI 3.5.8-2 to be acceptable, except for the potential aging effect loss of form due to sedimentation (sludge) buildup in the North Anna Service Water Reservoir (SWR). The applicant states that up to 4 feet of sludge buildup can be tolerated before loss of function, and through 20 years of operation, 1-foot of sludge buildups has occurred in the SWR. Using linear extrapolation, there would be 3 feet of sludge buildup after 60 years. However, there is no specific basis for linear extrapolation. Considering the relatively small margin for error, a one-time inspection prior to entering the period of extended operation would be appropriate. In discussing the applicant's response to RAI 3.5.8-2, the applicant committed, in a letter dated May 22, 2002 (Serial No. 02-277), to do a one-time inspection of the North Anna SWR to determine the level of sludge buildups. In its letter dated July 25, 2002, the applicant stated that the UFSAR Supplement Section 18.2.17, "Service Water System Inspections," has been modified to include the required sludge buildup measurement. Since the applicant has completed this action, the staff considers confirmatory action 3.8.2-1 closed.

Considering the applicant's AMR of the soil used in earthen structures at North Anna and Surry and the applicant's commitment to do a one-time inspection of the North Anna SWR, The staff found the applicant's approach for evaluating the applicable aging effects for the soil used in the earthen structures at both North Anna and Surry to be reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effects for the soil used in the earthen structures at both North Anna and Surry.

3.8.2.2.2 Aging Management Programs

The aging management activities used by the applicant to manage the above aging effects are the Civil Engineering Structural Inspection, Chemistry Control Program for Primary Systems, Buried Piping and Valve Inspection Activities, General-condition-monitoring activities, Infrequently Accessed Area Inspection Activities, and Work Control Process. Within a given category of structural members, the aging management utilized by the applicant depends on the environment. For example, for steel beams, the Civil Engineering Structural Inspection AMA is used for beams in an air environment, while the General-condition-monitoring activities AMA is used for beams that may be exposed to a borated water leakage environment. This breakdown is defined for each structural member in Tables 3.5.2 through 3.5.8 of each LRA. A complete evaluation of the above aging management activities is found in Sections 3.3.1 and 3.3.4 of this SER. In this section, the staff reviewed the applicability of the above aging management activities to the components in structures outside containment. The staff has identified the following issue related to the Work Control Process and Civil Engineering Structural Inspection AMAs.

The Work Control Process and Civil Engineering Structural Inspection AMAs are credited with managing cracking and change in material properties for elastomer materials used in structures outside containment; however, neither of these AMAs identify the inspection of elastomer materials to be within their program scopes. In RAIs 3.5.5-1 and 3.5.6-4 the staff requested the applicant to describe how these two AMAs manage the aging of elastomer materials. In response, the applicant stated that although elastomer materials are not specifically listed in the Work Control Process activity description in Section B2.2.19 of both applications, they are included in this activity as non-metallic materials in air and in atmosphere/weather environments, as clarified In its response to RAI B2.2.19-3. In addition, the applicant stated that although not specifically stated in the program description, the rubber gaskets used in the intake structures and the polysulfide sealant material used in the earthen structures are within the scope of the Civil Engineering Structural Inspection AMA. The Civil Engineering Structural Inspection activity relies on preventive maintenance activities initiated through the Work Control Process AMA for the inspection and management of the rubber gaskets used in the intake structures. In addition, the Civil Engineering Structural Inspection AMA relies on surveillance test activities initiated through the Work Control Process AMA for the inspection and management of the polysulfide sealant material used in the earthen structures. The applicant stated that the scope of the Civil Engineering Structural Inspection AMA will be clarified to include elastomers and their associated aging effects in the revised program summary description for the UFSAR Supplement that will be presented to the NRC staff in a future submittal. In its letter dated July 25, 2002, the applicant stated that the UFSAR Supplement Section 18.2.6, Civil Engineering Structural Inspections has been modified to include change in material properties as an aging effect for both concrete and elastomer sealant and/or gasket materials.

Since the applicant has completed this action, the staff finds the clarification given by the applicant concerning the aging management of elastomer materials by the Civil Engineering Structural Inspection and Work Control Process AMAs to be acceptable.

On the basis of the information discussed above and the review of the aging management activities in Sections 3.3.1 and 3.3.4 of this SER, the staff concludes that the applicant has demonstrated that the aging effects for the components in structures outside containment will be adequately managed during the period of extended operation.

3.8.2.3 Conclusions

The staff has reviewed the information in Sections 3.5.2 through 3.5.8 of each LRA and the applicable aging management activity descriptions in Appendix B of each LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in structures outside containment will be adequately managed so that there is reasonable assurance that these structural components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.8.3 NSSS Equipment Supports

3.8.3.1 Summary of Technical Information in the Application

Section 3.5.9 of each LRA provides the applicant's aging management review of the NSSS equipment supports. Table 3.5.9-1 of each LRA summarizes the applicant's aging management review of the structural members that comprise the NSSS equipment supports by providing (1) the passive function, (2) the material group, (3) the environment, (4) the aging effects requiring management, and (5) the specific aging management activities that manage the aging effects. A description of the NSSS equipment supports is provided in Section 2.4.9 of each LRA.

The applicant states in Section 3.5.9 of each LRA that it utilized the Westinghouse Owners Group Life Cycle Management and License Renewal Program Topical Report, WCAP-14422, "License Renewal Evaluation: Aging Management for Reactor Coolant System Supports," in its aging management evaluation of the NSSS equipment supports. The applicant states that the scope of the NSSS supports described in the topical report bound the installed NSSS supports with the following clarifications:

- the generic parameters for temperature, environments, materials, and support configurations contained in the topical report were not used by the applicant for the aging management review of the NSSS supports. Instead, the applicant used actual values and configurations applicable to the installed NSSS equipment supports
- the topical report for the reactor coolant system supports included the pressurizer surge line supports. The applicant evaluates the aging effects for the pressurizer surge line supports in Section 3.5.10 of each LRA
- the topical report states that the NSSS equipment supports are not generally designed to specifically use bolted joint connections requiring pre-load. The applicant's review has determined that there are situations where pre-loading has been utilized and has included these situations in the aging management review of the NSSS equipment supports

The materials of construction for the NSSS equipment support structural members, which are subject to aging management review, are (1) carbon steel, (2) low-alloy steel, (3) maraging steel, (4) stainless steel, and (5) bronze. In addition, some of the NSSS support structural members have been impregnated with a low-friction lubricant (Lubrite).

The NSSS equipment supports are located in the containment and exposed to the containment air environment. In addition, the applicant states that the external surfaces of the NSSS equipment supports may also be exposed to borated water leakage conditions. The only NSSS equipment support structural member within the scope of license renewal that is in contact with fluids is the internal surfaces of the neutron shield annular tank. The applicant states that the tank is filled with treated-water with an operating temperature of 120°F.

3.8.3.1.1 Aging Effects

In Section 3.5.9 of each LRA, the applicant identified the following applicable aging effects for the NSSS support structural members:

- loss of material from carbon steel, low-alloy steel, maraging steel, and bronze structural members in a borated water leakage environment
- loss of material from carbon steel, low-ally steel, and maraging steel structural members in treated-water or air environments
- cracking of high strength maraging steel bolting in an air environment

3.8.3.1.2 Aging Management Programs

The applicant credits the following aging management activities with managing the identified aging effects for the NSSS support structural members:

- infrequently accessed area inspection activities
- chemistry control program for primary systems
- ISI program - component and component support inspections
- boric acid corrosion surveillance

A description of these aging management activities is provided in Appendix B of each LRA. The applicant concludes that the effects of aging associated with the NSSS equipment supports will be adequately managed by these aging management activities such that there is reasonable assurance that the intended functions will be maintained consistent with the current licensing basis during the period of extended operation. A description of the general structural supports is provided in Section 2.4.10 of each LRA.

3.8.3.2 Staff Evaluation

In Section 3.5.9 of each LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results - Structures," and the applicable aging management activity descriptions provided in Appendix B of each LRA to determine whether the aging effects for the NSSS equipment support structural members have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.8.3.2.1 Aging Effects

In Section 3.5.9 of each LRA, the applicant provides an aging management review of the NSSS equipment support structural members. The methodology used to perform the aging management review for specific aging effects is described in Appendix C of each LRA. This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management programs credited for the NSSS equipment support structural members. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the NSSS equipment supports.

Steel: Appendix C of each LRA lists (1) loss of material, (2) cracking, (3) loss of pre-load, and (4) reduction in fracture toughness as plausible aging effects for carbon, low-alloy, maraging, and stainless steel NSSS equipment support structural members.

For the loss of material aging effect, the applicant identified corrosion and boric acid wastage as plausible aging mechanisms for the steel NSSS equipment support structural members. The applicant briefly describes both of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.9 of each LRA, identifies loss of material as an aging effect requiring management for carbon steel, low-alloy steel, and maraging steel structural members in air, treated-water, and borated water leakage environments.

For the cracking aging effect, the applicant identified stress-corrosion cracking (SCC) as a plausible aging mechanism for the steel NSSS equipment support structural members. The applicant briefly describes SCC in Appendix C of each LRA and states that SCC was evaluated during the aging management reviews. Table 3.5.9 of each LRA, identifies cracking as an aging effect requiring management for high strength maraging steel bolting in an air environment.

Bronze: Only the NSSS equipment support bearing plate is made of bronze. The applicant identified loss of material due to borated water leakage as the only aging effect requiring management for bronze material.

Lubrite: Lubrite is identified by a footnote to Table 3.5.9 of each LRA. Footnote 1 to Table 3.5.9 of each LRA states that the bronze bearing plate is impregnated with Lubrite lubricant. The applicant states that Lubrite has been evaluated for the worst case fluence levels at the reactor vessel sliding supports. There are no aging effects requiring management for Lubrite since it is essentially pure graphite with some trace amounts of metallic oxides to enhance its lubricity.

For each of the above material (steel, bronze, and lubrite) the staff identified the following RAIs:

Footnote 2 in Table 3.5.9-1 of each LRA identifies other high-strength bolting used in NSSS equipment supports. However, cracking is not identified as an applicable aging effect by the applicant for the other high-strength bolting. Footnote 2 indicates that for the neutron shield tank support structure and the reactor coolant pumps, steam generator, and pressurizer support structures, the carbon steel and low-alloy steel material group includes high-strength bolting. This high-strength bolting is potentially susceptible to SCC and may require aging management. In RAI 3.5.9-4, the staff requested that the applicant provide a technical justification for this omission. In response, the applicant stated the following:

> Stress corrosion cracking (SCC) is the aging mechanism that results in cracking of high strength bolting. As discussed in each LRA, Section C3.2.1, SCC requires the simultaneous action of a corrosive environment, sustained tensile stress, and a susceptible material. Elimination of any one of these elements will eliminate the susceptibility to SCC. Additionally, the susceptibility of materials to SCC is dependent on the magnitude of these elements. In other words, the greater the tensile stress, the greater the yield strength of the material, or the more severe the environment; the more susceptible a given material is to SCC.
>
> Although the industry has experienced instances of cracking of carbon steel and low-alloy steel bolting due to SCC, these failures have been attributed to high yield strength materials (>150 ksi). For the carbon and low-alloy steel high-strength bolting utilized in the supports (identified by Footnote 2 in Table 3.5.9-1 and Footnote 3 in Table 3.5.10-1 of the application), the material yield strength ranges from 140 to 160 ksi. Therefore, the yield strengths for these materials only marginally exceed the threshold at which materials are considered susceptible to SCC. These bolts are located in a sheltered-air environment that is not corrosive and, therefore, is not conducive to initiation of SCC in these materials. Therefore, there is reasonable assurance that cracking of the carbon and low-alloy steel high-strength bolting of the Surry and North Anna NSSS equipment supports and general structural supports is not an aging effect that requires management. In addition, a review of plant-specific operating experience did not identify cracking of these bolting materials in support applications.

After reviewing the applicant's response to RAI 3.5.9-4, the staff requested further information in a supplemental RAI pertaining to the specific yield strengths for the other high-strength bolting used in the NSSS equipment supports. In a letter dated May 22, 2002 (Serial No. 02-163), the applicant listed yield strengths for eight different high-strength bolt materials. OF the eight bolt materials, only three have yield strengths higher than 150 ksi; the other five have yield strengths near to or below 130 ksi. In addition, the applicant reiterated its response to RAI 3.5.9-4 that stated that SCC requires the simultaneous action of a corrosive environment, sustained tensile stress, and a susceptible material. Elimination of any one of these elements will eliminate susceptibility to SCC. Since the other high-strength bolts used for the NSSS equipment supports are in a hot and dry environment, the staff concurs with the applicant that SCC is not an applicable aging mechanism.

The staff review of the applicant's use of the Westinghouse Owners Group (WOG) Generic Technical Report (GTR), WCAP-14422, for the NSSS equipment supports focused on deviations listed by the applicant from the GTR recommendations. Section 4.1 of the NRC staff's safety evaluation of the WOG GTR on NSSS equipment supports identifies 16 applicant-action-items which staff required from the applicant in order to conclude that the aging of the components of the RCS supports, within the scope of the WOG GTR, will be adequately managed. The staff received the applicant's AMR of the NSSS equipment supports with respect to each of the action items and, in particular, focused on action item 16. The action item #16 requests that the plant-specific programs that deviate from the WOG GTR recommended aging management programs be identified and justified. In RAI 3.5.9-1 the staff requested that the applicant provide more information on the following deviations from the WOG GTR.

1. The WOG GTR recommends an aging management program (AMP-1.2) for concrete local to reactor coolant system (RCS) support concrete embedments. The applicant responded to the action items 1, 10, 13, 14, 15, and 16, and indicated that the concrete portion of RCS-supports are evaluated under Containment, and that there are no aging effects that require management for concrete structural members within Containment. The applicant should identify this as a deviation to the WOG GTR and provide technical justification for concluding that the aging effects due to aggressive chemical attack and corrosion as described in the WOG GTR do not require management.

2. The WOG GTR recommends an aging management program to manage aging effects due to aggressive chemical attack and corrosion in RCS support steel components (AMP-1.1). The program includes IWF inspections, leakage identification walkdowns, and leakage monitoring. In response to Applicant Action Items 10 and 14, the applicant did not provide any detailed information on a leakage monitoring program. If a leakage monitoring program is not credited for managing these aging effects, this should be identified as a deviation from the WOG GTR and a technical justification for its omission should be provided.

3. Materials of construction of NSSS supports identified in LRA Section 3.5.9 include "maraging" steel. This material is not included in the WOG GTR. The applicant should identify this as a deviation to the WOG GTR, and provide a description and results of a plant-specific aging management review for components fabricated from this material.

4. LRA Table 3.5.9-1 identifies bronze as a bearing plate material. This material is not included in the WOG GTR. Section 2.3 of the WOG GTR indicates that the type of base material used for the Lubrite plates is ASTM A-48. The applicant should identify

this as a deviation to the WOG GTR, and provide a description and results of a plant-specific aging management review for components fabricated from bronze.

In response to the four items listed in RAI 3.5.9-1, the applicant stated:

As discussed in Section 3.5.9 of the application, the applicant has performed a plant-specific aging management review for the NSSS Supports at Surry and North Anna. As such, the applicant has provided sufficient information in the license renewal application to document the plant-specific aging management review results, as required by 10 CFR 54.21, without sole reliance on the conclusions of the WOG GTR. Although the WOG GTR was used as a technical reference for the aging management review, deviations from the WOG GTR were not specifically identified in the application, and are not addressed in the response to RAI 3.5.9-1. However, the applicant has addressed the Applicant Action Items resulting from the NRC FSER for this GTR and included this information in the application in Table 3.5.9-W1 to aid the NRC staff review:

- the aging effects of loss of material, change in material properties, and cracking of concrete local to RCS support concrete embedments will be managed as described In its response to RAI 3.5-7
- loss of material due to boric acid wastage for the RCS supports is managed with the Boric Acid Corrosion Surveillance activities described in Section B2.2.3 of the application. These activities include inspections for evidence of borated water leakage, reviews of inspection results, and evaluations of the effects of leakage. Inspections for borated water leakage are performed at a frequency of each refueling outage. These inspections are performed to comply with the requirements of NRC Generic Letter 88-05. If leakage is found, evaluation of the affected components, including NSSS Supports as applicable, are initiated in accordance with the Corrective Action System. Therefore, the leakage monitoring is performed in accordance with the Boric Acid Corrosion Surveillance activity
- Section 2.4.1 and Table 2-4 of the WOG GTR identify the materials most commonly specified for the RCS supports. Although not identified in Section 2.4.1 and Table 2-4, the potential for stress-corrosion cracking of maraging steel is discussed in WOG GTR, Section 3.2.1. A plant-specific aging management review has been performed for maraging steel in accordance with the methodology outlined in Appendix C of the application. The results of this plant-specific aging management review are provided in LRA Table 3.5.9-1
- Section 2.4.1 and Table 2-4 of the WOG GTR identify the materials most commonly specified for the RCS supports. Bronze is not identified in this section or table and is not discussed elsewhere in the WOG GTR. A plant-specific aging management review has been performed for bronze in accordance with the methodology outlined in Appendix C of the application. The results of this plant-specific aging management review are provided in LRA Table 3.5.9-1

The staff found the applicant's responses to each part of RAI 3.5.9-1 to be acceptable. The applicant is correct that the WOG GTR does discuss high-nickel maraging steel in Section 3.2.1 under "Aging Effect Evaluation" for stress corrosion cracking. In addition, the applicant provides for aging of concrete local to RCS support concrete embedments, management of loss of material due to boric acid wastage for the RCS supports, and a plant-specific AMR for bronze as a bearing plate material.

Section 4.1 of the WOG GTR states that RCS support components are not generally designed to use bolted joint connections requiring pre-load. However, it also states that in the event that pre-load is important for a specific support design, a locking mechanism can be used to ensure that the pre-load is not lost. If a locking mechanism is not used, a plant-specific CLB inspection program may include an inspection of the connection for loss of preload, if deemed necessary. Applicant action item 16 of the staff's SER on the WOG GTR also requires that the applicant identify a program to ensure that proper pre-load is retained for the component supports within the scope of the WOG GTR. Section 3.5.9 of each LRA indicates that preloading has been utilized, but it did not indicate that locking mechanisms were used or that an inspection program is in place. Therefore, the staff requested in RAI 3.5.9-2 that the applicant identify the specific supports which rely on bolt pre-load to remain functional, identify the bolt materials, and provide technical justification for not providing a locking mechanism or performing inspections.

In response to RAI 3.5.9-2 the applicant stated that based on the NSSS supports materials and environment at Surry and North Anna, loss of bolt pre-load is not an aging effect requiring management. As described in the response to applicant action item 16, Part 4 of 7 (Page 3-365 of the Surry LRA and Page 3-361 of the North Anna LRA), the maximum temperature to which the bolting is exposed is less than the threshold temperature for stress relaxation that could result in loss of pre-load. Therefore, there are no bolting applications where loss of pre-load is an aging effect requiring management for NSSS Supports.

The staff initially considered the applicant's response to RAI 3.5.9-2 to be unacceptable. Section 4.1 of the WOG GTR is not related to stress relaxation, caused by elevated temperature, as the cause of loss of bolt preload. Where preload is necessary to meet intended function but a locking mechanism is not used, the WOG GTR recommends inspection for loss of preload. However, the staff recognized that the applicant is already managing these high-strength bolts for cracking and loss of material and considers this to be sufficient.

The staff found the applicant's approach for evaluating the applicable aging effects for the NSSS equipment support structural members to be reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effects for the structural members comprising the NSSS equipment supports.

3.8.3.2.2 Aging Management Programs

The aging management activities used by the applicant to manage the above aging effects are the Infrequently Accessed Area Inspection Activities, Chemistry Control Program for Primary Systems, ISI Program - Component and Component Support Inspections, and Boric Acid Corrosion Surveillance. Within a given category of structural members, the aging management utilized by the applicant depends on the environment. For example, for the neutron shield tank, the Infrequently Accessed Area Inspection Activities AMA is used for the portion of the tank in air, the Boric Acid Corrosion Surveillance AMA is used for the portion of the tank exposed to borated water leakage, and the Chemistry Control Program for Primary Systems AMA is used for the portion of the tank exposed to treated-water. This breakdown is defined for each structural member in Table 3.5.9 of each LRA. A complete evaluation of the above aging management activities is found in Sections 3.3.1 and 3.3.4 of this SER. In this section, the staff reviewed the applicability of the above aging management activities to the NSSS equipment support structural members. The staff has identified the following issue related to the ISI Program - Component and Component Support Inspections AMA.

The staff notes that the ISI Program - Component and Component Support Inspections (IWF Category F-A) is credited for managing cracking of high strength maraging steel bolting in an air environment. The staff has a concern about the adequacy of VT-3 visual inspection, which is required by Category F-A, to detect cracking in high strength bolting before there is loss of function. In RAI 3.5.9-5, the staff requested that the applicant provide additional technical justification on the adequacy of this inspection method for managing stress corrosion cracking in high strength support bolts.

In response, the applicant stated that the provisions of ASME Section XI, Subsection IWF constitute the current licensing basis requirements for inspection of supports for ASME Class 1, 2, 3, and MC components for Surry and North Anna. These requirements are the current industry standards for inspection of nuclear component supports. In addition, the NRC staff has accepted the inspection provisions of ASME Section XI, Subsection IWF as an effective aging management program for cracking of structural bolting in its Safety Evaluation Reports for Calvert Cliffs (NUREG-1705) and Arkansas Nuclear One Unit 1 (NUREG-1743) license renewal applications. Therefore, the aging management approach for NSSS Supports described in the license renewal applications for Surry and North Anna is consistent with the current licensing basis requirements and NRC staff accepted methodologies for license renewal.

The staff recognizes that the visual VT-3 examinations specified by ASME Section XI, Subsection IWF, may be inadequate to directly detect the degradation of bolts by SCC; however, the staff has determined that the VT-3 examinations will detect conditions of any leakage or other contaminants that may cause degradation of bolts by SCC. The staff has previously accepted visual VT-3 examination for high-strength bolting, which constitutes the applicant's current licensing basis, as a means for detecting conditions to SCC. The acceptance of a visual VT-3 examination is based on the applicant's prior completion of a baseline evaluation of the bolts, as described in Section 4.2.2 of the WOG GTR. During the baseline evaluation, the structural integrity of the bolts in the RCS supports was examined by the applicant. In a letter to the staff on May 22, 2002 (Serial No. 02-163), the applicant stated that the evidence of SCC was not observed during the baseline inspection and, as stated in its response RAI 3.5.9-4, SCC requires the simultaneous action of a corrosive environment, sustained tensile stress, and a susceptible material. Elimination of any one of these elements will eliminate susceptibility to SCC. Since the high-strength bolts (> 150 ksi) used for the NSSS equipment supports are in a normally hot and dry environment, the staff concurs with the applicant that a VT-3 visual examination is sufficient to detect any changes to the bolting environment, which may lead to SCC of the high-strength bolts. Thus, the applicant's response to RAI 3.5.9-5 is acceptable to the staff.

On the basis of the information discussed above and the review of the aging management activities in Sections 3.3.1 and 3.3.4 of this SER, the staff concludes that the applicant has demonstrated that the aging effects for the NSSS equipment support structural members will be adequately managed during the period of extended operation.

3.8.3.3 Conclusions

The staff has reviewed the information in Section 3.5.9 of each LRA and the applicable aging management activity descriptions in Appendix B of each LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the NSSS equipment support structural members will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.8.4 General Structural Supports

3.8.4.1 Summary of Technical Information in the Application

Section 3.5.10 of each LRA provides the applicant's aging management review of the general structural supports. Table 3.5.10-1 of each LRA summarizes the applicant's aging management review of the general structural support components by providing (1) the passive function, (2) the material group, (3) the environment, (4) the aging effects requiring management, and (5) the specific aging management activities that manage the aging effects.

The materials used for general structural supports are (1) carbon steel, (2) low-alloy steel, (3) stainless steel, (4) aluminum, (5) and copper alloys. Structural support items include structural plates, sheet steel, clamps, brackets, cable trays, conduits, struts, and spring hangers. Most of the structural support items are made from carbon steel and low-alloy steel; however, aluminum is used for cable trays and conduits inside buildings, except for containment. Also, stainless steel structural support items include sliding pipe supports and supports that are submerged in borated water.

The different environments for the structural supports include (1) containment air, (2) other indoor areas of the plant, (3) outdoors, (4) borated water, and (5) raw water.

3.8.4.1.1 Aging Effects

In Section 3.5.10 of each LRA, the applicant identified the following applicable aging effects for general structural supports:

- loss of material from carbon steel and low-alloy steel support components in an air or atmosphere/weather environment
- loss of material from carbon steel and low-alloy steel support components in a raw water environment
- loss of material from stainless steel supports in a treated-water (borated water) environment
- loss of material from carbon steel and low-alloy steel support components in a borated water leakage environment

3.8.4.1.2 Aging Management Programs

The applicant credits the following aging management activities with managing the identified aging effects for general structural supports:

- augmented inspection activities
- battery rack inspections
- boric acid corrosion surveillance
- chemistry control program for primary systems
- ISI program - component and component support inspections
- general-condition-monitoring activities
- infrequently accessed area inspection activities

A description of these aging management activities is provided in Appendix B of each LRA. The applicant concludes that the effects of aging associated with the general structural supports will be adequately managed by these aging management activities such that there is reasonable assurance that the intended functions will be maintained consistent with the current licensing basis during the period of extended operation.

3.8.4.2 Staff Evaluation

In addition to Section 3.5.10 of each LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results - Structures," and the applicable aging management activity descriptions provided in Appendix B of each LRA to determine whether the aging effects for the components comprising the general structural supports have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.8.4.2.1 Aging Effects

In Section 3.5.10 of each LRA, the applicant provides an aging management review of several components which comprise the general structural supports. The methodology used to perform the aging management review for specific aging effects is described in Appendix C of each LRA. This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management programs credited for the components which comprise the general structural supports and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the components which comprise the general structural supports.

Steel: Appendix C of each LRA lists loss of material and cracking as plausible aging effects for carbon, low-alloy, and stainless steel components which comprise the general structural supports.

For the loss of material aging effect, the applicant identified corrosion and boric acid wastage as plausible aging mechanisms for the components which comprise the general structural supports. The applicant briefly describes both of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.10 of each LRA, identifies loss of material as an aging effect requiring management for carbon steel and low-alloy steel components in air, atmosphere/weather, borated water leakage, and raw water environments. Loss of material is also identified as an aging effect requiring management for stainless steel supports in a treated-water environment.

For the cracking aging effect, the applicant identified stress-corrosion cracking (SCC) as a plausible aging mechanism for the components which comprise the general structural supports. The applicant briefly describes SCC in Appendix C of each LRA and states that SCC was evaluated during the aging management reviews. Table 3.5.10 of each LRA, does not identify cracking as an aging effect requiring management for any of the components which comprise the general structural supports. The staff's evaluation of potential cracking due to SCC of high-strength bolting used for the general structural supports is discussed in RAI 3.5.9-4, which is covered in previous section of this SER. In response to RAI 3.5.9-4, the applicant demonstrated that cracking of the high-strength bolting used for general structural support is not an aging effect that requires management. The staff concurs with the applicant's finding.

Aluminum: Only the electrical cable trays are made of aluminum. The applicant does not identify any aging effects requiring management for the aluminum cable trays. The staff concurs with the applicant's finding.

Bronze: The applicant identified loss of material due to borated water leakage as the only aging effect requiring management for bronze. The Surry RHR pump support bearing plate is the only component made of bronze that is exposed to boric acid environment. The staff concurs with the applicant's finding.

Lubrite: Lubrite is identified by a footnote to Table 3.5.10 of each LRA. Footnote 1 to Table 3.5.10 of each LRA states that the bronze bearing plate is impregnated with Lubrite lubricant. The applicant states that Lubrite has been evaluated for the worst case fluence levels at the reactor vessel sliding supports. There are no aging effects requiring management for Lubrite since it is essentially pure graphite with some trace amounts of metallic oxides to enhance its lubricity.

While the staff concurs with the applicant's identification of the above aging effects for the components which comprise the general structural supports, the staff identified two areas where clarifications and additional information was required. In RAI 3.5.10-1, the staff requested further information regarding two issues.

1. In each LRA Section 3.5.9 and 3.5.10, the applicant recognizes the need to manage supports for the purpose of maintaining the intended functions of the associated SCs under design load conditions. However, the applicant did not identify the need to manage those supports that are within the scope of license renewal and perform the functions of allowing for thermal expansion and seismic restraint. Buildup of debris or material on the non-moving surface can cause an obstruction that can impede the ability to expand and, therefore, prohibit the ability to allow for thermal expansion. As such, the staff requests that the applicant include fouling of the component surface as an applicable aging effect for these supports and to identify the AMA that will be used to manage this fouling.

2. In each LRA Section 2.4.10, the applicant indicates that supports for mechanical equipment (e.g., fans) are within the scope of the general structural support AMR. Fans and other mechanical equipment are often mounted on vibration isolating supports,

which employ various non-metallic materials to absorb equipment vibration. The staff considers change in material property and cracking as aging effects requiring management for vibration isolation supports. However, the applicant's AMR does not identify any non-metallic materials, and does not specifically indicate that vibration isolating supports are within the scope of the AMR for general structural supports. Therefore, the staff requests that the applicant: (1) clarify whether there are any vibration isolating supports within the scope of license renewal and (2) describe the AMR for vibration isolating supports, including the materials and environments, the applicable aging effects, and the AMAs credited to manage aging.

In response to the two items requested by the staff in RAI 3.5.10-1, the applicant stated:

- there are supports within the scope of license renewal that are designed to restrain components in certain directions while allowing thermal expansion in the other directions. Although fouling of the component surface is not identified in each LRA as an aging effect requiring management, such degradation would be identified by aging management activities relied on for managing the effects of aging for these supports. Therefore, fouling of component support surfaces that could affect the function to allow thermal expansion will be managed by the ISI Program – Component and Component Support Inspections, General-condition-monitoring activities, and Infrequently Accessed Area Inspection Activities
- there are supports within the scope of license renewal that are designed for vibration isolation which utilize non-metallic materials. These support elements are considered to be an integral part of the overall structural support component and are not uniquely identified in the application. Degradation associated with these non-metallic support elements would be identified by aging management activities relied on for managing the entire structural support assembly. Therefore, aging effects of non-metallic materials used in vibration isolating supports are managed by the ISI Program – Component and Component Support Inspections, General-condition-monitoring activities, and Infrequently Accessed Area Inspection Activities

Since the applicant has committed to manage fouling of support component surfaces as an applicable aging effect through its ISI Program – Component and Component Support Inspections, General-condition-monitoring activities, and Infrequently Accessed Area Inspection Activities AMAs, the staff found the applicant's response to the first item in RAI 3.5.10-1 to be acceptable. In addition, the staff finds that the applicant's response to the second item in RAI 3.5.10-1 to be acceptable since the applicant stated that the inspection of the non-metallic support elements, although not uniquely identified in the applications, is part of the AMAs used for managing the aging effects of the entire structural support assembly.

In RAI 3.5.10-2, the staff requested that the applicant address the potential for reduction in concrete anchor capacity due to degradation of the embedded portion of the steel anchor or the degradation of the concrete and grout surrounding the anchor. In response to RAI 3.5.10-2, the applicant stated that the potential aging effects for the portion of the steel anchor embedded in concrete, or potential aging effects for the concrete and grout surrounding the anchor, are evaluated along the associated structure concrete. The applicant stated that the aging effects of loss of material, cracking, and change in material properties will be managed for concrete components as described in response to RAI 3.5-7. Thus, the applicant's commitment to manage concrete aging, in response to RAI 3.5-7, will include managing potential degradation of the embedded portion of the steel anchor as well as degradation of the concrete and grout surrounding the anchor. Therefore, the applicant's response to RAI 3.5.10-2 is acceptable to the staff.

3.8.4.2.2 Aging Management Programs

The aging management activities used by the applicant to manage the above aging effects are the Augmented Inspection Activities, Battery Rack Inspections, Boric Acid Corrosion Surveillance, Chemistry Control Program for Primary Systems, ISI Program - Component and Component Support Inspections, General-condition-monitoring activities, and the Infrequently Accessed Area Inspection Activities. Within a given category of structural members, the aging management utilized by the applicant depends on the environment. This breakdown is defined for each structural member in Table 3.5.10 of each LRA. A complete evaluation of the above aging management activities is found in Sections 3.3.1 and 3.3.4 of this SER. In this section, the staff reviewed the applicability of the above aging management activities to the components which comprise the general structural supports. On the basis of the review of the aging management activities in Sections 3.3.1 and 3.3.4 of this SER, the staff concludes that the applicant has demonstrated that the aging effects for the components which comprise the general structural supports will be adequately managed during the period of extended operation.

3.8.4.3 Conclusions

The staff has reviewed the information in Section 3.5.10 of each LRA and the applicable aging management activity descriptions in Appendix B of each LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components which comprise the general structural supports will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.8.5 Miscellaneous Structural Commodities

3.8.5.1 Summary of Technical Information in the Application

Section 3.5.11 of each LRA provides the applicant's aging management review of the miscellaneous structural commodities. Table 3.5.11-1 of each LRA summarizes the applicant's aging management review of the miscellaneous structural commodities by providing (1) the passive function, (2) the material group, (3) the environment, (4) the aging effects requiring management, and (5) the specific aging management activities that manage the aging effects.

The materials of construction for the miscellaneous structural members are (1) carbon steel, (2) low-alloy steel, (3) galvanized steel, (4) stainless steel, (5) aluminum, (6) a variety of ceramics and polymers, and (7) elastomers.

The different environments for the miscellaneous structural members are (1) atmosphere/weather, (2) sheltered-air, and (3) containment air. In addition, the applicant states that miscellaneous structural commodities may be located in areas with piping systems that contain boric acid and could be exposed to a borated water leakage environment.

3.8.5.1.1 Aging Effects

In Section 3.5.11 of each LRA the applicant identified the following applicable aging effects for the miscellaneous structural members:

- change in material properties of ceramics and polymers in an air environment
- change in material properties of elastomers in an atmosphere/weather environment
- cracking of elastomers in an atmosphere/weather environment
- loss of material from carbon steel and low-alloy steel components in air, atmosphere/weather, or borated water leakage environments
- loss of material from ceramics and polymers in an air environment
- separation and cracking/delamination of ceramics and polymers in an air environment

3.8.5.1.2 Aging Management Programs

The applicant credits the following aging management activities with managing the identified aging effects for the miscellaneous structural members:

- fire protection program
- boric acid corrosion surveillance
- general-condition-monitoring activities
- work control process

A description of these aging management activities is provided in Appendix B of each LRA. The applicant concludes that the effects of aging associated with the miscellaneous structural members will be adequately managed by these aging management activities such that there is reasonable assurance that the intended functions will be maintained consistent with the current licensing basis during the period of extended operation.

3.8.5.2 Staff Evaluation

In addition to Section 3.5.11 of each LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results - Structures," and the applicable aging management activity descriptions provided in Appendix B of each LRA to determine whether the aging effects for the components comprising the miscellaneous structural commodities have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.8.5.2.1 Aging Effects

In Section 3.5.11 of each LRA, the applicant provides an aging management review of several components which comprise the miscellaneous structural commodities. The methodology used to perform the aging management review for specific aging effects is described in Appendix C of each LRA. This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management programs credited for the components which comprise the miscellaneous structural commodities and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the components which comprise the miscellaneous structural commodities.

Steel and Aluminum: Appendix C of each LRA lists loss of material as the only plausible aging effect for carbon steel, low-alloy steel, stainless steel, galvanized steel, and aluminum components which comprise the miscellaneous structural commodities.

For the loss of material aging effect, the applicant identified corrosion and boric acid wastage as plausible aging mechanisms for the components which comprise the miscellaneous structural commodities. The applicant briefly describes both of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.11 in each LRA identifies loss of material as an aging effect requiring management for carbon steel and low-alloy steel components in air, atmosphere/weather, and borated water leakage environments. Loss of material is also identified as an aging effect requiring management for galvanized steel components in atmosphere/weather or borated water leakage environments.

Ceramics, Polymers, and Elastomers: Appendix C of each LRA lists (1) loss of material, (2) cracking, and (3) change in material properties as plausible aging effects for the components which comprise the miscellaneous structural commodities.

For the loss of material aging effect, the applicant identified abrasion and flaking as plausible aging mechanisms for the components which comprise the miscellaneous structural commodities. The applicant briefly describes both of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.11 in each LRA identifies loss of material as an aging effect requiring management for ceramics and polymers in an air environment (NAS 1/2 only).

For the cracking aging effect, the applicant identified (1) irradiation, (2) thermal exposure, (3) ultraviolet radiation, (4) differential movement, (5) shrinkage, and (6) vibration as plausible aging mechanisms for the components which comprise the miscellaneous structural commodities. The applicant briefly describes each of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.11 in each LRA identifies cracking as an aging effect requiring management for ceramics and polymers in an air environment. Also, cracking is identified as an aging effect requiring management for elastomers in an atmosphere/weather environment.

For the change in material properties aging effect, the applicant identified irradiation and thermal exposure as plausible aging mechanism for the components which comprise the miscellaneous structural commodities. The applicant briefly describes both of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.11 in each LRA identifies change in material properties as an aging effect requiring management for ceramics and polymers in an air environment. Also, change in material properties is identified as an aging effect requiring management for elastomers in an atmosphere/weather environment and an air environment (SPS 1/2 only).

The staff concurs that these are the applicable aging effects requiring management for the ceramic, polymer and elastomer structural members comprising the miscellaneous structural commodities. However, the staff notes that Section 3.5.11 of the North Anna LRA indicates that 3M E53A mats and mineral wool bats used for fire wraps and gypsum boards, which serves a fire protection function, do not require aging management. The staff requested further clarification on this issue in RAI 3.5.11-1.

In response to RAI 3.5.11-1, the applicant stated that:

> Intermittent wetting in an air environment has been considered during the assessment of the aging of structural steel members. As identified in Table 3.0-2 of the license renewal application, structural steel members associated with mechanical system components may have the potential for condensation or intermittent wetting. Therefore, structural members have been generally assumed to be subject to an intermittently wetted environment. When there is no potential for condensation or other source of intermittent wetting, such as for bus duct enclosures, electrical component supports, panels and cabinets, and switchgear enclosures in the control room, the switchgear rooms, and the vicinity of the electrical equipment, an exception to this general application of an intermittent wetting environment is taken and documented in the application.

The staff concurs that these are the applicable aging effects requiring management for the ceramic, polymer, and elastomer structural members comprising the miscellaneous structural commodities. However, in RAI 3.5.11-1, the staff requested further information concerning the following three items.

> In both LRAs, Table 3.5.11-1, the applicant states (in Footnote 1) that carbon and low-alloy steel bus duct enclosures, electrical component supports, panels and cabinets, and switchgear enclosures in an air environment do not require aging management because they are not subject to intermittent wetting. This statement implies that intermittent wetting is a prerequisite for loss of material from carbon and low-alloy steel in an air environment. This does not appear to be consistent with the applicant's previous determinations that carbon steel and low-alloy steel plant components in an air environment require aging management for loss of material. Therefore, the staff requests that the applicant provide additional information concerning intermittent wetting as a prerequisite for causing loss of material, and also to describe how humidity was addressed in the North Anna and Surry AMRs.
>
> The staff also notes that the applicant identified a borated water leakage environment for junction, terminal, and pull boxes, and for panels and cabinets, but not for bus duct enclosures, electrical component supports (inside panels and cabinets), and switchgear enclosures. Therefore, the staff requests that the applicant provide an explanation for excluding a borated water leakage environment for bus duct enclosures, electrical component supports (inside panels and cabinets), and switchgear enclosures.
>
> The applicant's AMR for North Anna identifies 3M E53A mats and mineral wool bats as materials used for fire wraps and also identifies gypsum boards, which

serve a fire protection function. In NAS LRA, Table 3.5.11-1, the applicant has indicated that these materials in an air environment do not require aging management. No basis for this conclusion is provided in the LRA. Therefore, the staff requests that the applicant provide a technical justification for this conclusion and to specifically address the potential effect of humidity on degradation of the fire protection function of these materials.

As discussed in Section C3.1.1 of the application, external surfaces of carbon and low-alloy steel piping and components, located within structures, have not experienced corrosion degradation that would affect the intended function of components due to humidity in the absence of cyclic or intermittent wetting.

The bus duct enclosures and switchgear enclosures that are within the scope of license renewal are located in normal and emergency switchgear rooms within the Service Building. There are no piping systems that contain boric acid in normal and emergency switchgear rooms. Therefore, the bus duct and switchgear enclosures are not evaluated for boric acid wastage.

The electrical component supports that are within panels and cabinets are not subjected to boric acid leakage because the panels and cabinets are enclosed, and there are no piping systems that contain boric acid within the panels and cabinets.

The applicant considered humidity in the evaluation of potential aging effects for 3M E53A mats, mineral wool batts, and gypsum boards and concluded that, based on a review of manufacturers technical information, humidity does not result in aging effects requiring management. The potential for condensation due to humidity was also considered. The 3M E53A mats and mineral wool batts are wrapped in water-resistant foil with seams sealed with foil tape. The gypsum board is W/R Type C board, which is water-resistant. Therefore, the evaluation concluded that condensation due to humidity would not result in aging effects requiring management. Additionally, a review of operating experience has identified no issues related to degradation of these materials due to humidity.

The staff found the applicant's response to RAI 3.5.11-1 to be comprehensive in describing the AMRs for these components and, thus considers the applicant's response to be acceptable.

3.8.5.2.2 Aging Management Programs

The aging management activities used by the applicant to manage the above aging effects are the Fire protection program, General-condition-monitoring activities, Boric Acid Corrosion Surveillance, and Work Control Process. Within a given category of structural members, the aging management utilized by the applicant depends on the environment. This breakdown is defined for each structural member in Table 3.5.11 of each LRA. A complete evaluation of the above aging management activities is found in Section 3.3.1 of this SER. In this section, the staff reviewed the applicability of the above aging management activities to the components which comprise the miscellaneous structural commodities. On the basis of the review of the aging management activities in Section 3.3.1 of this SER, the staff concludes that the applicant has demonstrated that the aging effects for the components which comprise the miscellaneous structural commodities will be adequately managed during the period of extended operation.

3.8.5.3 Conclusions

The staff has reviewed the information in Section 3.5.11 of each LRA and the applicable aging management activity descriptions in Appendix B of each LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components which comprise the miscellaneous structural commodities will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.8.6 Load-handling Cranes and Devices

3.8.6.1 Summary of Technical Information in the Application

Section 3.5.12 of each LRA provides the applicant's aging management review of the load-handling cranes and devices. Table 3.5.12-1 of each LRA summarizes the applicant's aging management review of the load-handling cranes and devices by providing (1) the passive function, (2) the material group, (3) the environment, (4) the aging effects requiring management, and (5) the specific aging management activities that manage the aging effects.

The materials of construction used for load-handling cranes and devices are (1) carbon steel, (2) low-alloy steel, and (3) stainless steel.

The different environments for the load-handling cranes and devices are (1) containment air, (2) sheltered-air, and (3) outdoor environments. The applicant indicates that the surfaces of certain load-handling cranes and devices may also be exposed to borated water leakage conditions. Also, the new fuel transfer elevator is attached to the liner of the spent fuel pool an is submerged in treated-water. The spent fuel pool cooling system maintains the temperature of the spent fuel pool water between 75°F and 100°F.

3.8.6.1.1 Aging Effects

In Section 3.5.12 of each LRA, the applicant identified the following applicable aging effects for the load-handling cranes and devices:

- loss of material from carbon steel and low-alloy steel load-handling cranes and devices components in an air or atmosphere/weather environment
- loss of material from stainless steel components in a treated-water environment
- loss of material from carbon steel and low-alloy steel components in a borated water leakage environment

3.8.6.1.2 Aging Management Programs

The applicant credits the following aging management activities with managing the identified aging effects for the load-handling cranes and devices:

- general-condition-monitoring activities

- boric acid corrosion surveillance
- chemistry control program for primary systems
- inspection activities - load-handling cranes and devices

A description of these aging management activities is provided in Appendix B of each LRA. The applicant concludes that the aging effects associated with the load-handling cranes and devices will be adequately managed by these aging management activities such that there is reasonable assurance that the intended functions will be maintained consistent with the current licensing basis during the period of extended operation.

3.8.6.2 Staff Evaluation

In addition to Section 3.5.12 of each LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results - Structures," and the applicable aging management activity descriptions provided in Appendix B of each LRA to determine whether the aging effects for the components comprising the load-handling cranes and devices have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.8.6.2.1 Aging Effects

In Section 3.5.12 of each LRA, the applicant provides an aging management review of several components which comprise the load-handling cranes and devices. The methodology used to perform the aging management review for specific aging effects is described in Appendix C of each LRA. This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management programs credited for the components which comprise the load-handling cranes and devices and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the components which comprise the load-handling cranes and devices.

Steel: Appendix C of each LRA lists loss of material and cracking as the plausible aging effects for carbon steel, low-alloy steel, and stainless steel components which comprise the load-handling cranes and devices.

For the loss of material aging effect, the applicant identified corrosion and boric acid wastage as plausible aging mechanisms for the components which comprise the load-handling cranes and devices. The applicant briefly describes both of the above aging mechanisms in Appendix C of each LRA and states that each mechanism was evaluated during the aging management reviews. Table 3.5.12 of each LRA, identifies loss of material as an aging effect requiring management for carbon steel and low-alloy steel components in air, atmosphere/weather, and borated water leakage environments. Loss of material is also identified as an aging effect requiring management for stainless steel components in a treated-water environment.

The staff found the applicant's approach for evaluating the applicable aging effects for the steel components comprising the load-handling cranes and devices to be reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effects for steel components which comprise the load-handling cranes and devices.

3.8.6.2.2 Aging Management Programs

The aging management activities used by the applicant to manage the above aging effects are the Chemistry Control Program for Primary Systems, General-condition-monitoring activities, Boric Acid Corrosion Surveillance, and Inspection Activities - Load-handling Cranes and Devices. Within a given category of structural members, the aging management utilized by the applicant depends on the environment. This breakdown is defined for each structural member in Table 3.5.12 of each LRA. A complete evaluation of the above aging management activities is found in Section 3.3.1 of this SER. In this section, the staff reviewed the applicability of the above aging management activities to the components which comprise the load-handling cranes and devices. On the basis of the review of the aging management activities in Section 3.3.1 of this SER, the staff concludes that the applicant has demonstrated that the aging effects for the components which comprise the load-handling cranes and devices will be adequately managed during the period of extended operation.

3.8.6.3 Conclusions

The staff has reviewed the information in Section 3.5.12 of each LRA and the applicable aging management activity descriptions in Appendix B of each LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components which comprise the load-handling cranes and devices will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.9 Aging Management of Electrical and Instrumentation and Controls

In the North Anna and Surry LRAs, the applicant describes its AMR results for electrical/I&C components requiring an AMR at North Anna and Surry in Section 3.6, "Aging Management of Electrical and Instrument and Controls." The staff reviewed this section of the applications to determine whether the applicant has demonstrated that the effect of aging on the electrical/I&C components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

On the basis of this review, the staff requested additional information in letters to the applicant dated October 11, 2001, (Ref. 3.9-1) and October 22, 2001 (Ref. 3.9-2). The applicant responded to the request for additional information in letters dated November 30, 2001 (Ref. 3.9-3), and February 1, 2002 (Ref. 3.9-4). The applicant also provided AMR material in its July 11, 2002 letter (Ref 3.9-12) on the additional system (offsite power) brought into scope, as discussed in Section 2.5 of this report. The AMR material in the July 11, 2002 letter that relates to electrical components is evaluated here, along with the applicant's other electrical/I&C AMRs.

3.9.1 Bus Duct, Aluminum Tube Bus, Aluminum Bus Bars, and Ceramic Insulators

In the North Anna and Surry LRAs, Section 2.5.1, "Bus Duct," the applicant identified certain non-segregated bus ducts that are within the scope of license renewal and require an AMR. Section 2.5.1.3 of this SER provides the staff's evaluation of Section 2.5.1 of the LRAs and concludes that the applicant has appropriately identified the bus ducts that require an AMR. This section of our SER evaluates the applicant's AMR of those bus ducts.

In its July 11, 2002 letter the applicant identified certain electrical components that are within the scope of license renewal (offsite power system recovery under SBO) and require an AMR. The components are aluminum tube bus, aluminum bus bars, ceramic insulators, bare distribution conductors, and insulated cables and connectors. The aluminum tube bus, aluminum bus bars, and ceramic insulators are evaluated in this section of the SER. Bare distribution conductors and insulated cables and connectors are evaluated in Section 3.9.2, "Cables and Connectors."

3.9.1.1 Summary of Technical Information in the Application - Bus Duct

3.9.1.1.1 Aging Effects

Table 3.6.1-1 in Section 3.6.1 of the North Anna and Surry LRAs identifies the bus duct components that have been evaluated for aging management. The components of the bus duct are identified as the bus assembly and the bus support assembly. The table indicates the bus assembly's function is to conduct electricity. Its materials are metal conductors and organic compounds, and it operates in an air environment. The bus support assembly's function is to provide structural and/or functional support to the bus assembly. It is made of organic compounds and it also operates in an air environment.

Section 3.6.1 in the North Anna LRA indicates that the specific organic compound used in the North Anna bus duct components is fiberglass-reinforced polyester resin (glastic). The specific type of metal conductor used at North Anna is aluminum bar.

Section 3.6.1 in the Surry LRA indicates that the specific organic compounds used in the Surry bus duct components are fiberglass reinforced polyester resin (glastic) and noryl. The specific type of metal conductor used at Surry is copper bar.

The bus assembly bars at North Anna and Surry are covered with molded insulation. The connection areas are silver-plated and use stainless steel bolting. All bus connections are insulated with splice boots without the use of tape or filler material. In each LRA Section 3.6.1, the applicant indicates that, at both sites, the bus duct construction is in compliance with ANSI C37.20 which specifies an allowable hottest-spot conductor and splice temperature rise of 65 °C (117 °F) in a 40 °C (104 °F) ambient environment.

The applicant has evaluated the environment in which the bus ducts operate at North Anna and Surry. In the North Anna and Surry LRAs, Section 3.6.1, the applicant indicates that, at both sites, the bus ducts are located in the emergency switchgear room and the normal switchgear room and are exposed to an air environment.

At North Anna the emergency switchgear room temperature varies between 70 °F and 85 °F and the relative humidity is normally 50%. The normal switchgear room temperature varies between 70 °F and 120 °F. The 60-year design ionizing dose is 390 rads during normal operation.

At Surry the emergency switchgear room temperature is maintained at approximately 80°F and the relative humidity ranges from 35% to 50%. The normal switchgear room temperature varies between 70 °F and 104 °F. The 60-year design ionizing dose is 390 rads during normal operation.

In each LRA Section 3.6.1, the applicant indicates that the stated temperature range includes worst-case upper limits that are not typical of "normal" operation and that "normal" ambient temperature in a sheltered-air environment is not in excess of 40 °C (104°F.) Higher temperatures are expected only during periods when outside ambient air is at seasonal highs and then only when area ventilation is not operating. Each LRA states that bus ducts in sheltered-air environments will, in fact, operate in an ambient temperature below 40 °C (104°F) for a significant portion of their 60-year operating life. The applicant therefore has used this ambient value to determine the 60-year serviceability of bus ducts.

3.9.1.1.2 Aging Management Programs

The applicant concludes in Section 3.6.1 of the North Anna and Surry LRAs that there are no aging effects on the bus ducts within the scope of license renewal that require management during the period of extended operation. Thus, the intended functions of the bus ducts will be maintained consistent with the current licensing basis during the period of extended operation.

The conclusion that there are no aging effects requiring management during the period of extended operation is based on the applicants review of the environment of the bus duct installation and the materials of construction.

3.9.1.2 Staff Evaluation - Bus Duct

The staff evaluated the information on aging management of bus ducts presented in Section 3.6.1 of the North Anna and Surry LRAs. The evaluation was conducted to determine if the applicant has demonstrated that the effects of aging on the bus ducts will be adequately managed consistent with its CLB throughout the period of extended operation, in accordance with 10 CFR 54.21(a)(3).

3.9.1.2.1 Aging Effects

As indicated above, the North Anna and Surry LRAs state that the bus duct construction is in compliance with ANSI C37.20, which specifies an allowable hottest-spot conductor and splice temperature rise of 65°C (117°F) in a 40°C (104°F) ambient environment. With the exception of the North Anna normal switchgear room, the bus ducts subject to an AMR are all located in an air environment with a temperature range that is within the ANSI C37.20 specified ambient environment of 104°F.

The applicant states in the LRA that the North Anna normal switchgear room temperature varies between 70°F and 120°F. This is in excess of the ANSI C37.20 specified ambient environment of 104°F. The LRA indicates, however, that this temperature range includes worst-case upper limits that are not typical of "normal" operation; and "normal" ambient temperature in a sheltered-air environment is not in excess of 104 °F. The North Anna LRA states that higher temperatures are expected only during periods when outside ambient air is at seasonal highs and then only when area ventilation is not operating. The LRA states that bus ducts in sheltered-air environments will, in fact, operate in an ambient temperature below 104 °F for a significant portion of their 60-year operating life. The applicant therefore has used this ambient value to determine the 60-year serviceability of bus ducts.

The staff agrees with the applicant's use of 104°F as the ambient value to determine the 60-year serviceability of the bus ducts that are subject to an AMR. This is based upon the statements that the bus ducts will operate in an ambient temperature below 104°F for a significant portion of their 60-year operating life, and higher temperatures only occur when area ventilation is not operating and outside ambient air is at seasonal highs.

3.9.1.2.2 Aging Management Programs

In the North Anna and Surry LRAs, the applicant states that based on a review of the environment of the bus duct installation and the materials of construction, there are no aging effects requiring management during the period of extended operation for the bus ducts within the scope of license renewal. The staff agrees with the applicant's assessment based upon the use of the 104°F ambient environment discussed above.

3.9.1.3 Staff Evaluation - Aluminum Tube Bus, Aluminum Bus Bars, and Ceramic Insulators

In its July 11, 2002 letter, the applicant identified certain electrical components that are within the scope of license renewal (required for offsite power system recovery under SBO) and require an AMR. The aluminum tube bus, aluminum bus bars, and ceramic insulators are evaluated here.

Aluminum Tube Bus and Aluminum Bus Bars

Aluminum tube buses and aluminum bus bars are in the offsite power path to the transfer buses at North Anna, both in an outdoor environment. Aluminum tube buses are in the Surry power path for offsite power at the reserve station service transformers and are also located in an outdoor environment.

The applicant states that the only material of construction for the bus components that is subject to an aging management review is aluminum and that aluminum in an outdoor environment is not a new combination in the North Anna or Surry LRA; however, it was not previously evaluated as an electrical conductor. The applicant further indicates that both North Anna and Surry are located in an area that is mostly agricultural with no significant industries nearby that could contribute to adverse/corrosive air quality conditions. The applicant therefore concludes there are no aging effects for aluminum bus components requiring management for the period of extended operation.

The staff finds that since the aluminum bus components are not exposed to corrosive air, they do not require management for the period of extended operation.

Ceramic Insulators

The applicant indicates that ceramic material is not new to the Surry LRA, but was not previously evaluated as an electrical insulator. Aging effects for insulators requiring evaluation are surface contamination and loss of material. There are two types of insulators in service at Surry on the portion of the offsite power path within scope: post insulators and strain/suspension insulators. Only post insulators are used at North Anna in the portion of the offsite power path within scope.

The applicant states that loss of material due to mechanical wear is not a concern for the post insulators because they are fixed and have no moving pivot points. The applicant states, however, that loss of material may be a potential aging effect for strain/suspension insulators if they are subjected to significant movement. The strain/suspension insulators are designed with joints to allow movement when the wind swings the supported conductor wires. If frequent enough, this swinging can cause wear in the metal contact points of the insulator string and between an insulator and the supporting hardware. The applicant states that wind loading that could cause strain/suspension insulator wear is not a concern for the overhead conductors at Surry because of the low-elevation, and short-span construction. This aging mechanism is more of a concern for transmission conductors that are installed in longer and higher spans that are more susceptible to wind loading. The applicant concludes that loss of material, due to wear of the Surry and North Anna insulators, is not an aging effect requiring management for the period of extended operation.

The staff finds that since there are no moving pivot points in post insulators and wind loading is not a concern for strain/suspension insulators used on low-elevation, and short-span overhead conductors, neither type of insulator requires management for loss of material over the period of extended operation.

With regard to surface contamination of the ceramic insulators, the applicant states that airborne particulate materials such as dust and industrial effluents can contaminate insulator surfaces. A large buildup of contamination enables the conductor voltage to track along the surface more easily and can lead to insulator flashover. The buildup of surface contamination is gradual and adhesion is minimized by the glazed insulator surface. Contamination of this type is washed away by rain. The applicant states that both North Anna and Surry receive sufficient annual rainfall to remove contamination buildup. The National Weather Surface 30-year average rainfall for the North Anna area is greater than 43 inches annually and for Surry it is greater than 44 inches annually. The applicant concludes that surface contamination of insulators at North Anna and Surry is not an aging effect requiring management for the period of extended operation.

The staff agrees that normal rainfall at North Anna and Surry will wash away any surface contamination on the ceramic insulators before the buildup leads to insulator flashover. The staff therefore concludes that surface contamination is not an aging effect requiring management for the period of extended operation for North Anna and Surry insulators.

3.9.1.4 Conclusions

The staff agrees with the applicant's conclusion that no aging effects for the bus duct, aluminum tube bus, aluminum bus bars, and ceramic insulators within the scope of license renewal at North Anna and Surry require management during the period of extended operation.

3.9.2 Cables and Connectors

In the North Anna and Surry LRAs, Section 2.5.2, "Cables and Connectors," the applicant identified certain cables and connectors that are within the scope of license renewal and require an AMR. Section 2.5.2.3 of this SER provides the staff's evaluation of Section 2.5.2 of the LRAs and concludes that the applicant has appropriately identified the cables and connectors that require an AMR. This section of our SER evaluates the applicant's AMR of those cables and connectors.

In its July 11, 2002 letter the applicant identified certain electrical components that are within the scope of license renewal (required for offsite power system recovery from an SBO event) and require an AMR. The components are aluminum tube bus, aluminum bus bars, ceramic insulators, bare distribution conductors, and insulated cables and connectors. The aluminum tube bus, aluminum bus bars, and ceramic insulators are evaluated above in Section 3.9.1.3. Bare distribution conductors and insulated cables and connectors are evaluated here.

3.9.2.1 Summary of Technical Information in the Application

3.9.2.1.1 Aging Effects

Table 3.6.2-1 in Section 3.6.2 of the North Anna and Surry LRAs identifies the characteristics of cables and connectors used in their AMR. The table indicates the function of the cables and connectors is to conduct electricity. The materials are metal conductors and organic compounds. The cables and connectors operate in air, raw water, and soil environments.

In the North Anna and Surry LRAs, Section 3.6.2, the applicant listed the following organic compounds used in the construction of cables and connectors at both sites:

- cross-linked polyethylene (XLPE)
- ethylene propylene rubber (EPR)
- kevlar (fiber optic)
- phenolic
- polyamide (nylon)
- polyolefin (Raychem)
- polyimide (Kapton)
- polyvinyl chloride (PVC)
- silicone rubber (SiR)
- cellulose-filled melamine
- mylar

Section 3.6.2 in the North Anna LRA lists polysulfone as an additional organic compound used in the construction of cables and connectors at the North Anna site but not used at Surry. The applicant's July 11, 2002 letter identifies tree-retardant (TR) XLPE as an additional organic compound used in the 34.5 kV circuit at Surry, but not used at the North Anna site.

Section 3.6.2 in the North Anna and Surry LRAs lists the following metal conductors used in the construction of cables and connectors at both sites:

- copper/copper alloys
- aluminum/aluminum alloys
- copper-constantan
- iron-constantan
- chromel-alumel

With regard to the environment, Section 3.6.2 in the North Anna and Surry LRAs states that cables and connectors are installed throughout plant buildings and yard areas in various raceway configurations and/or direct buried. They are exposed to atmosphere/weather, containment air, sheltered air, and soil environments. Section 3.6.2 states that the aging management reviews for power and I&C cables and connectors used the most severe plant cable environments and considered design values for normal operation in evaluating each component group.

Section 3.6.2 in the North Anna and Surry LRAs states that Table 3.0-2 in each LRA provides environmental conditions for areas containing cables and conductors, with some exceptions discussed below . This table provides details of the external service environment used in the AMRs. The external service environment is broken down into four categories in the table. The four categories are:

- air
  - sheltered-air
  - containment air
- atmosphere/weather
- borated water leakage
- soil

The North Anna LRA identified an exception to the radiation limit specified for a sheltered air environment in Table 3.0-2. It states that the Table 3.0-2 radiation limit is applicable to the volume control tank area of the Surry auxiliary building only. The North Anna LRA also identified an exception to the Table 3.0-2 temperature limits for power and I&C cables located in the upper elevations of the main steam valve house. The applicant has defined North Anna-specific radiation and temperature limits for cables in these areas.

The Surry LRA identified an exception to the radiation limit specified for a sheltered air environment in Table 3.0-2. It states that the Table 3.0-2 radiation limit is applicable to the volume control tank area of the Surry auxiliary building only and that no cables are in that area of the auxiliary building. The Surry LRA also identified an exception to the Table 3.0-2 temperature limits for power and I&C cables located in the upper elevations of the main steam valve house and the emergency service water pump house. The applicant has defined Surry-specific radiation and temperature limits for cables in these areas.

The applicant also states in the North Anna and Surry LRAs that the ambient temperature ranges shown in Table 3.0-2 for sheltered-air environments include worst-case upper limits that are not typical of "normal" operation. The applicant states that "normal" ambient temperature in a sheltered-air environment is not in excess of 40°C/104°F. Higher temperatures would be expected only during periods when outside ambient air is at seasonal highs and then only when area ventilation is not operating. Each LRA states that cables in sheltered-air environments will, in fact, operate in an ambient temperature below 40°C/104°F for a significant portion of their 60-year operating life. The applicant therefore has used this ambient value to determine the 60-year serviceability of cables in all areas at North Anna and Surry except the containment, main steam valve house, and emergency service water pump house (this last is Surry specific).

3.9.2.1.2 Aging Management Programs

In the North Anna and Surry LRAs, Section 3.6.2, the applicant states that the 60-year exposure of cable and connectors to the effects of heat, radiation, and operating environments was evaluated. The evaluation included a review of radiation tests data to evaluate radiation aging effects and the use of Arrhenius methodology. The applicant determined that none of the cable materials supporting intended functions are exposed to 60-year thermal or radiation operating environments that are in excess of the material 60-year thermal or radiation service limits. They concluded therefore that no aging effect resulting from heat or radiation require management.

With regard to the effects of water, Section 3.6.2 states that medium-voltage cables have been evaluated for the formation of water trees. Water treeing is a degradation and long-term failure phenomenon that has been documented for medium-voltage electrical cable with certain extruded polyethylene and EPRI insulations. Water treeing can occur in energized cables that are subjected to long-term wetting. The applicant states that no continuously energized medium voltage cables in the scope of license renewal are subjected to long-term wetting. Section 3.6.2 concludes, therefore, that no aging effects associated with formation of water trees require aging management through the period of extended operation.

Finally, the applicant states that a review of plant-specific operating experience at North Anna and Surry was conducted to identify any cable and connector aging effects that had not previously been addressed. The review did not identify any additional aging effects, and no licensee event reports on this subject identified.

3.9.2.2 Staff Evaluation

The staff evaluated the information on aging management presented in the North Anna and Surry LRAs, Section 3.6, and in the applicant's response to the staff RAIs dated November 30, 2001 (Ref 3.9-3), and February 1, 2002 (Ref 3.9-4). In its July 11, 2002 letter (Ref 3.9-12), the applicant identified additional electrical components that are within the scope of license renewal (require for offsite power system recovery under SBO) and require an AMR. The applicant indicated that the cable insulation type and operating environment combinations of the new non-EQ cables and connectors are covered in the Surry and North Anna LRAs, with only a few exceptions. The exceptions are evaluated in the following Section 3.9.2.2.1 under the topic "July 11, 2002 letter." The remaining combinations are already included in the LRAs are evaluated under the subheading "North Anna and Surry LRAs" along with the other LRA-covered non-EQ cable AMR topics. The staff evaluation was conducted to determine if there is reasonable assurance that the applicant has demonstrated that the effects of aging will be adequately managed consistent with the plant's CLB throughout the period of extended operation, in accordance with 10 CFR 54.21(a)(3).

3.9.2.2.1 Aging Effects

North Anna and Surry LRAs

In the North Anna and Surry LRAs, Section 3.6.2, the applicant does not identify any applicable aging effects for non-environmentally-qualified (non-EQ) cables. Industry operating experience indicates that aging of cables requires aging management. The staff therefore discussed this issue with the applicant in a June 19, 2001, telephone conference (Ref 3.9-5). The applicant agreed to consider developing an aging management program for cables and later informed the staff it intended to propose such a program. The staff spoke with the applicant about the contents of two draft aging management activities later provided by the applicant. In a letter dated October 11, 2001 (Ref 3.9-1), the staff formally requested the applicant to perform an aging management review of non-EQ cables consistent with industry operating experience, and submit aging management activities that demonstrate the applicable aging effects will be managed throughout the period of extended operation. The applicant responded in a letter dated November 30, 2001 (Ref 3.9-3), with a North Anna and Surry aging management activity for non-EQ cables and connectors within the scope of license renewal. Section 3.6.2.2.2 (Aging Management Programs) provides the staff's evaluation of this aging management activity.

In each LRA, Table 3.0-2, regarding the external service environments exposed to borated water leakage, the applicant states that "[t]his environment is not considered for in-scope cables and connectors since cables are insulated, splices are sealed, and terminations are protected by enclosures." With regard to electrical terminations protected by enclosures, operating experience has shown that water and borated water have migrated into enclosures and terminations by following cables or moving through conduits. As a result the staff asked the applicant (Ref 3.9-2) whether the cables and conduit that penetrate enclosures credited for protecting terminations are sealed to prevent the intrusion of borated water into the enclosure.

In a letter dated February 1, 2002, the applicant responded that the practice used at Surry and North Anna is to seal enclosures, and the cables and conduits that penetrate enclosures, to eliminate the possibility of borated water intrusion. The applicant has performed an operating experience review and has determined this to be an effective practice to eliminate this concern. The staff finds this response acceptable. This item is therefore closed.

In the North Anna and Surry LRAs, Section 3.6.2, the applicant identified polyimide (Kapton) as one of the organic compounds used in the construction of cables and connectors. Kapton insulation has a well-known vulnerability to moisture (e.g., Ref 3.9-6, Table 4-2, Note 6). However, the cable and connector aging management activity that the applicant committed to in its November 30, 2001, letter, only addresses wetted conditions for medium-voltage cables (water treeing). In an October 4, 2001, conference call (Ref 3.9-7), the applicant was asked to verify that the North Anna and Surry aging management activities address wetting of Kapton insulation or to provide the technical basis for not doing so.

The applicant stated that Section 3.6.2 in the North Anna and Surry LRAs is in error in identifying Kapton as one of the organic compounds used in the construction of non-EQ cables and connectors. The applicant explained that Kapton insulation is only used in the construction of EQ cables and connectors at North Anna and Surry and is not used in the construction of non-EQ cables and connectors. The staff finds this response acceptable. The staff's evaluation of EQ components is contained in Section 4.4 of this evaluation.

<u>July 11, 2002 letter</u>

In its July 11, 2002 letter (Ref 3.9-12), the applicant identified additional non-EQ cables and connectors in the offsite power path that are within the scope of license renewal (require for offsite power system recovery under SBO) and require an AMR. The applicant indicated that the cable insulation type and operating environment combinations of the additional non-EQ cables and connectors are covered in the Surry and North Anna LRAs, with only several exceptions. The exceptions are an additional power cable insulation material and bare overhead conductors at Surry and the operation of parts of the offsite circuits at Surry and North Anna at a high-voltage level of 34.5 kV. The staff's evaluation of the applicant's AMR of these new items follows.

<u>34.5 kV Insulated Power Cable and Additional Cable Insulation Material</u>

Sections of the offsite circuits newly in scope operate at 34.5 kV. These are the sections between the 34.5 kV circuit breakers in the North Anna and Surry switchyards and their respective RSSTs. The materials of construction for the insulated power cables in these circuits include materials previously evaluated in the North Anna and Surry LRAs; but not evaluated for application at the 34.5 kV voltage level. In addition one new cable type, a tree-retardant cross-linked polyethylene (TR XLPE) cable, is used in these circuits at Surry and has not previously been evaluated. As a result the applicant provided the results of its AMR of these 34.5 kV cables in its July 11, 2002 letter.

The applicant states that the exposed portions of the 34.5 kV cables are ultraviolet (UV) stabilized; therefore, UV damage is not an aging effect that requires management. The staff agrees that UV damage is not an aging effect requiring management for cables that are UV stabilized.

The applicant states that there are no potential adverse thermal environments in the 34.5 kV cable runs, and radiation in the area of these cables is negligible. The applicant has also provided information indicating that the sizing of the 34.5 kV cables would result in operation ranging from 39% to 69% of rated capacity under maximum RSST or transfer bus duct loading. Under normal operating conditions the cables would be loaded from 7% to 50% of their rated capacity. The applicant concludes that ohmic heating is not a concern, and thermal or radiation embrittlement of the cable insulation is not an aging effect that requires management. The staff agrees that, at the levels of thermal and radiation environments indicated, thermal or radiation embrittlement of the 34.5 kV cable insulation is not an aging effect requiring management.

Portions of the 34.5 kV insulated cable runs at North Anna and Surry are installed in conduit, duct bank, and cable trench with a sand bed, and direct buried, with various manholes. These runs are inaccessible except at the manholes and may be exposed to condensation and wetting at manholes. Staff guidance used in past license renewal reviews is that medium-voltage cables in the range of 5 kV to 15 kV in such an environment, under certain conditions, could be prone to water treeing or a decrease of dielectric strength of the conductor insulation. This can potentially lead to electrical failure. With respect to the offsite circuits that are now included within the scope of license renewal, these underground circuits on the primary side of the startup transformers will operate at voltages higher than 15 kV. "Electrical Cable and Termination Aging Management Guideline," SAND96-0344 (Ref 3.9-6, page 4-25) states that "water treeing has historically been more prevalent in higher voltage cables; proportionately few occurrences have been noted for cables operated below 15 kV." On this basis the staff concludes that the higher voltage cables are also prone to these aging effects, and past guidance used for inaccessible medium-voltage cables is also applicable to inaccessible cables operated at voltages greater than 15 kV.

For the inaccessible 34.5 kV cables at North Anna and Surry, the licensee states in its July 11, 2002 letter:

> Intermittent wetting of cables due to precipitation and drainage is not considered significant wetting. Manholes are subject to wetting from entry of precipitation and groundwater. If water collects in manholes and places cable in a standing water condition, then the potential for significant wetting exists.

The applicant concludes that intermittent wetting of the inaccessible 34.5 kV cables at North Anna and Surry alone would not warrant aging management. However, the applicant concludes that significant wetting of the inaccessible 34.5 kV cables is an aging effect that requires management. The staff agrees that intermittent wetting of the inaccessible 34.5 kV cables does not warrant aging management but that significant wetting of these cables does require management. The applicant's definition of significant wetting is consistent with the definition of "significant moisture" (e.g., cable in standing water) used in staff guidance. The applicant's definition of intermittent wetting is also consistent with the staff's understanding of what is not considered to be significant moisture (i.e., normal rain and drain). The staff evaluation of the applicant's aging management program in this area is contained in the following Section 3.9.2.2.2.

<u>Overhead Bare Distribution Conductors</u>

Overhead bare distribution conductors are used in a portion of the newly scoped-in 34.5 kV offsite power circuits, between the 34.5 circuit breakers in the Surry switchyard and RSST A and RSST B. The applicant states in its July 11, 2002 letter that the aging effects for bare distribution conductors in an outdoor environment that require evaluation are loss of conductor material resulting from corrosion and aeolian (wind) vibration. The Surry overhead bare distribution conductors are 477 kcmil all-aluminum cables and are designed and installed in accordance with the National Electrical Safety Code. The applicant states that the most prevalent mechanism contributing to loss of material of an all-aluminum cable is aluminum strand pitting corrosion. The applicant states that corrosion of an all-aluminum cable is a very slow acting aging mechanism, depending largely on air quality, and states that Surry is located in an area that is mostly agricultural with no significant nearby industries that could contribute to adverse/corrosive air quality. The applicant concludes that loss of material due to corrosion, therefore, is not an aging effect requiring management for the period of extended operation.

The staff finds that since severe air quality is not a concern at Surry, all-aluminum cables do not require management for the period of extended operation.

With regard to aeolian vibration of the overhead conductors, the applicant states this can be caused by wind loading over large unprotected spans. The Surry overhead conductors utilize low-elevation and short-span construction. The applicant states that this aging mechanism is more of a concern for transmission conductors that are installed in longer and higher spans which are more susceptible to wind loading. Thus, the applicant concludes that loss of material as a result of conductor vibration or sway is not an aging effect requiring management for the period of extended operation.

The staff finds that, because the Surry overhead conductors utilize low-elevation and short-span construction, they do not require management for loss of material due to aeolian vibration or sway over the period of extended operation.

3.9.2.2.2 Aging Management Programs

The applicant provided an aging management activity for non-EQ cables and connectors within the scope of license renewal in a letter dated November 30, 2001 (Ref 3.9-3.) The applicant described the aging management activity in terms of the aging management program attributes provided in the Standard Review Plan for License Renewal. The staff reviewed the 10 program attributes in the applicant's aging management activity, utilizing guidance provided in the GALL Report for the attributes. The staff found that the submitted aging management activity is essentially a visual inspection program that addresses age-related degradation of cable jackets and connector coverings that can result from exposure to high temperature or radiation or to wetting. The visual inspection program covers equipment categories that are addressed under three separate programs in the GALL Report. The three GALL Report programs are XI.E1, "Electrical Cables and Connections not Subject to 10 CFR 50.49 Environmental Qualification Requirements," XI.E2, "Electrical Cables not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits," and XI.E3, "Inaccessible Medium-voltage Cables not Subject to 10 CFR 50.49 Environmental Qualification Requirements." [The following portion of our evaluation is arranged according to the guidance provided in the three GALL programs, in order to identify and evaluate the overriding technical issues involved.]

GALL Program XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"

The purpose of GALL Program XI.E1 is to provide reasonable assurance that the intended functions of non-EQ electrical cables and connections that are exposed to adverse localized environments caused by heat, radiation, or moisture will be maintained consistent with the current licensing basis through the period of extended operation. (The cables covered by this program do not include sensitive, low-signal-level instrumentation circuits or medium-voltage power cables exposed to moisture, which are included in GALL programs XI.E2 and XI.E3 respectively.) In this program a representative sample of accessible electrical cables and connections in adverse localized environments is visually inspected for cable and connection jacket surface anomalies. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible cables or connections.

The applicant's aging management activity for non-EQ cables and connectors within the scope of license renewal is consistent with the guidance contained in GALL program XI.E1. The staff therefore finds the aging management activity acceptable for the purpose of providing reasonable assurance that the intended functions of non-EQ electrical cables and connections (not including those types covered by GALL programs XI.E.2 and XI.E3) that are exposed to adverse localized environments caused by heat, radiation, or moisture will be maintained consistent with the current licensing basis through the period of extended operation.

GALL Program XI.E2, "Electrical Cables not Subject to Environmental Qualification Requirements used in Instrumentation Circuits"

The purpose of GALL program XI.E2 is to provide reasonable assurance that the intended functions of non-EQ electrical cables that 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 current licensing basis through the period of extended operation. In this program routine calibration tests performed as part of the plant surveillance test program are used to identify the potential existence of aging degradation. When an instrumentation loop is found to be out of calibration during routine surveillance testing, troubleshooting is performed on the loop, including the instrumentation cable.

The aging management activity submitted by the applicant does not utilize the calibration approach for non-EQ electrical cables used in low-level-signals sensitive circuits. Instead, these cables are simply combined with all other non-EQ cables under the visual inspection activity. The staff believed, however, that visual inspection alone would not necessarily detect reduced insulation resistance (IR) levels in cable insulation before the intended function is lost. Exposure of electrical cables to adverse localized environments caused by heat or radiation can result in reduced IR. A reduction in IR will cause an increase in leakage currents between conductors and from individual conductors to ground, and is a concern for low-level-signals sensitive circuits such as radiation and nuclear instrumentation circuits since it may contribute to inaccuracies in the instrument loop. Because low-level-signal instrumentation circuits may operate with signals that are normally in the low milliamp range or less, they can be affected by extremely low levels of leakage current. Routine calibration tests performed as part of the plant surveillance test program can be used to identify the potential existence of this aging degradation.

The staff was not convinced that aging of these cables will initially occur on the outer casing resulting in sufficient damage that visual inspection will be effective in detecting the degradation before IR losses lead to a loss of intended function, particularly if the cables are also subject to moisture. Therefore, in a letter dated October 22, 2001 (Ref 3.9-2), the applicant was asked to provide a technical justification that will demonstrate that visual inspections will be effective in detecting damage before current leakage can affect instrument loop accuracy.

In a letter dated February 1, 2002, the applicant reiterated its view that, because these circuits operate with currents in the milliampere range or less, degradation of the conductor insulation would have to occur from externally applied stressors of heat or radiation. This would result in external degradation of the cable jacket that would likely be detected by visual inspection prior to loss of cable intended function. The applicant stated that a review of operating experience indicates that no instrument cables failures have occurred due to aging and that visual inspection would be effective in detecting cable degradation. The applicant also stated that the "Electrical Cable and Termination Aging Management Guideline," SAND96-0344, concludes in Section 1.4 that ". . . reliance on visual inspection techniques for the assessment of low-voltage cable and termination aging appears warranted since these techniques are effective at identifying degraded cables."

In addition to the applicant's response, the staff undertook its own review of several aging management references. Page 3-52 of the SAND96-0344 report (Ref 3.9-6) referenced by the applicant identified polyethylene-insulated instrumentation cables located in close proximity to fluorescent lighting that had developed spontaneous circumferential cracks in exposed portions of the insulation. For some of the affected cables the cracking was severe enough to expose the underlying conductor; however, no operational failures were documented as a result of this degradation.

The reason no operational failures were documented may be explained by information in the book, *Aging and Life Extension of Major Light Water Reactor Components*, edited by V.N. Shaw and P.E. MacDonald (Ref 3.9-9). On page 855 the book states that breaks in insulation systems that are dry and clean are normally not detectable with insulation resistance tests of 1000 V or less. On the same page the book also states insulation resistance tests can detect some types of gross insulation damage, cracking of insulation, and the breach of connector seals, provided there is enough humidity or moisture to make the exposed leakage surfaces conductive.

Electric Power Research Institute EPRI report TR-103834-P1-2 (Ref 3.9-10) also supports the above view. The report states, on page 1.4-8, that normal or high insulation resistance may not indicate undamaged insulation in that a throughwall cut or gouge filled with dry air may not significantly affect the insulation resistance. The SAND96-0344 report, on page 3-51, states that instances of low-voltage cable and wire shorting to ground induced by moisture (as indicated in the LERs) may, in fact, be due to moisture intrusion through preexisting cracks caused by thermal and/or radiation exposure.

In summary, it appears from this literature that visual inspection of low-voltage, low-signal-level instrumentation circuits can be an effective means to detect age-related degradation due to adverse localized environments. Because a moist environment can apparently hasten the failure of these circuits if they have previously undergone age-related degradation, the disposition of a degraded cable should consider the potential for moisture in the area of the degradation. The revised Corrective Actions attribute of the North Anna and Surry non-EQ cable monitoring activity provided in the applicant's July 11, 2002 letter indicates that the engineering evaluation called for in that attribute will consider the potential for moisture in the area of any anomalies. This is acceptable because the engineering evaluation will consider the potential for moisture in the area of the degradation.

The staff notes that the above finding on low-voltage instrumentation circuits is not necessarily the case for neutron monitoring system cables and radiation monitoring cables. The SAND96-0344 report (Ref 3.9-6) referenced by the applicant states on page 3-36 that neutron monitoring systems (including source, intermediate, and power range monitors) were put into a separate category based on (1) their substantial differences from a typical low- and medium-voltage power, control, and instrumentation circuits, and (2) the relatively large number of reports related to these devices in the database. The report states that neutron detectors are frequently energized at what is commonly referred to as "high" voltage, usually between 1 kV and 5 kV. This is not high voltage in the sense of power transmission voltage, but rather elevated with respect to other portions of the detecting circuit. The report included the lower voltage non detector portion of typical neutron monitoring equipment in the low-voltage equipment category, but put the 1 kV to 5 kV neutron detectors into a separate category that included neutron monitor cables and connectors.

The high-voltage portion of the neutron monitoring systems would appear to be a worst-case subset of the low-signal-level instrumentation circuit category. These circuits operate with low-level logarithmic signals and so 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 connectors. Radiation monitoring cables have also been found to be particularly sensitive to thermal effects. NRC Information Notice 97-45, Supplement 1, describes this phenomenon. The neutron monitoring circuits and radiation monitors, therefore, might be candidates for the calibration approach but not necessarily the visual inspection approach. The calibration approach was used for these circuits at the Calvert Cliffs Nuclear Power Plant. Page 6.1-22 of the Calvert Cliff's license renewal application (Ref 3.6-11) on states:

> The IR reduction effect can be a concern for circuits with sensitive, low level signals such as current transmitters, resistance temperature detectors, and thermocouples. It is especially a concern for channels with logarithmic signals such as radiation monitors and neutron monitoring instrumentation. The IR reduction effect contributes to inaccuracies in the instrument loop current signal (e.g., 4-20 ma) such that the measurement of the process variable (e.g., rads/hour) becomes more uncertain.

The North Anna and Surry applicant subsequently responded to this issue in a letter dated July 25, 2002 (Ref 3.9-13). The letter stated:

> The applicant has reviewed the neutron monitoring instrumentation cables and radiation monitoring cables installed at Surry and North Anna Power Stations which operate between 1 kV and 5 kV and transmit signals supporting a license renewal intended function. Results of this review have determined that the source, intermediate, and power range neutron detector cables are the only

> cables meeting the above criteria that are not included in the environmental qualification program (i.e. non-EQ cable).
>
> The source, intermediate, and power range neutron detector cables are frequently energized in the "high" voltage range, (i.e., 1 kV and 5 kV), and a reduction in insulation resistance (IR) could be a concern for these cables since reduced IR may contribute to inaccuracies in the instrument loop. The routine calibration tests performed as part of the plant surveillance test program will be used to identify the potential existence of this aging degradation. Separate correspondence (Serial No. 02-297 dated July 11, 2002) on this subject provided a supplemental response to RAI 3.6.2-1 which credits the normal calibration frequency specified in the plants' Technical Specifications to provide reasonable assurance that severe aging degradation will be detected prior to loss of the cables' intended function.

The staff finds the above response acceptable because the calibration approach will be used to identify the potential existence of aging degradation.

<u>GALL Program XI.E3, "Inaccessible Medium-Voltage Cables not Subject to 10 CFR 50.49 Environmental Qualification Requirements"</u>

The purpose of GALL program XI.E3 is to provide reasonable assurance that the intended functions of inaccessible non-EQ medium-voltage cables that are exposed to adverse localized environments caused by moisture while energized will be maintained consistent with the current licensing basis through the period of extended operation. When an energized medium-voltage cable is exposed to wet conditions for which it is not designed, water treeing or a decrease in dielectric strength of the conductor insulation can occur. This can potentially lead to electrical failure. In this program periodic actions are 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 necessary. If in-scope medium voltage cables are simultaneously exposed to significant moisture and significant voltage, the program calls for periodic testing to provide an indication of the condition of the conductor insulation. Significant moisture is defined as periodic exposure to moisture for more than a few days (e.g., cable in standing water). Periodic exposure to moisture for less than a few days (i.e., normal rain and drain) is not considered significant. Significant voltage exposure is defined as being subjected to system voltage more than 25% of the time.

The aging management activity submitted by the applicant combines the cable and connector visual inspection activity with visual inspection for "wetted conditions." The applicant, however, does not expect to find "wetted conditions" during the associated visual inspections. The aging management activity description states:

> Evaluations for cables at Surry and North Anna that are within the scope of license renewal indicate the expected absence of wetted conditions. This expectation is substantiated by the absence of any direct-buried medium voltage cable that is exposed to significant voltage (i.e., subjected to system voltage more than 25 percent of the time) at Surry and North Anna, and the design of manholes that contain in-scope medium voltage cables.

GALL program XI.E3 only calls for periodic testing of inaccessible medium-voltage cables that are exposed to significant moisture while *simultaneously* being exposed to significant voltage. Therefore, based upon the above statement regarding "the absence of any direct-buried medium voltage cable that is exposed to significant voltage," it appears that no cables at Surry and North Anna require periodic testing under the GALL program criteria. However, the aging management activity description also contains the following passage:

> The only non-EQ, medium-voltage cables of concern for potentially wetted conditions are the power cables for the service water pump motors at North Anna. Engineered features were installed to prevent these non-EQ medium-voltage cables from being exposed to significant moisture. The existence of drain holes in the bottom of manholes and the seals that were placed at manhole covers provide reasonable assurance that the cable will not become submerged. Periodic inspections will confirm the absence of standing water in the affected manholes.

It is not clear from this passage whether the cables for the service water pump motors at North Anna are subjected to system voltage more than 25% of the time (definition of significant voltage) or are of concern only because they can be exposed to significant moisture. If they are subjected to system voltage more than 25% of the time and are also simultaneously subjected to significant moisture (periodic exposure to moisture for more than a few days), the cables should be periodically tested consistent with GALL program XI.E3 guidance or a technical basis provided for why they are not. The acceptance criterion contained in the applicant's aging management activity is as follows:

> The acceptance criterion with respect to wetted conditions is the absence of exposure to significant moisture. Cable found to be submerged in standing water for more than a few days will be subject to an engineering evaluation and corrective action. Inspection results for the condition of non-EQ cables and connectors will be summarized in a documented engineering evaluation. Any anomalies resulting from the inspections will be dispositioned by Engineering. Occurrence of an anomaly that is adverse to quality will be entered into the Corrective Action System.

The implied definition of significant moisture in this excerpt (cable found to be submerged in standing water for more than a few days) is consistent with the GALL program XI.E3 definition of significant moisture. However, it still remains unclear whether the subject cables are exposed to significant voltage at the same time they are being subjected to significant moisture. If not, the cables do not require periodic testing under the criterion contained in GALL program XI.E3. The applicant's aging management activity in this regard would therefore be acceptable.

If the subject cables are, in fact, simultaneously exposed to significant voltage and moisture, then, consistent with the guidance provided in GALL under the third program attribute (Parameters Monitored or Inspected), the cables should be periodically tested or a technical basis provided for why they are not. The staff notes that the engineering evaluation required by the program attributes of the applicant's cable management activity for cables that do not meet the visual inspection acceptance criteria is consistent with the guidance in GALL program XI.E1 but not program XI.E3. GALL program XI.E3 provides that cables be periodically tested if they are simultaneously exposed to significant voltage and significant moisture. An engineering evaluation is performed following the periodic tests when the test acceptance criteria are not met. It is not performed in lieu of doing the testing when the visual inspection criteria are not met.

In a February 1, 2002 letter (Ref 3.9-4), the applicant provided a response to a staff question on significant moisture related to the medium-voltage cable issue. The response references a report (Ref 3.9-6) indicating EPR cables submerged in 90 °C water have a 47-month time to failure. The response reiterates that an engineering evaluation will be performed if the cables are found submerged, regardless of the potential duration; and the evaluation would consider performing a test to determine the condition of the cable insulation. The response did not resolve the issues addressed above, including the testing issue.

The applicant subsequently readdressed the above issues in its July 11, 2002, and July 25, 2002 letters. With regard to the question of whether the service water system cables are simultaneously exposed to significant voltage and significant moisture the July 25, 2002 letter states:

> In the LRAs, the applicant identified a medium-voltage cable in the service water system at North Anna that had the potential for wetting, but did not associate the cable with water treeing because the environment of the cable was being maintained in a dry condition. Subsequent to the initial submittal of the LRAs, additions in the license renewal scope associated with Station Blackout have been made for high-voltage cables that are also subject to potential wetted conditions. Per applicant's revised response to RAI 2.5-1 (Serial No. 02-297 dated July 11, 2002) the cable environment for these high-voltage power cables will also be maintained in the dry condition at both Surry and North Anna.

It is clear from the above that the applicant did not associate the service water system cables with significant moisture because the applicant intends to maintain the cables in a dry condition. This is also the case for the additional underground cables introduced as part of the expanded scope due to the offsite power/station blackout resolution. With regard to the disposition of the cables if they are found in a wetted condition in spite of the applicant's best efforts to keep them dry, the applicant's July 25, 2002 letter also speaks to this issue. It indicates that the corrective action attribute of the Non-EQ Cable Monitoring program has been revised to provide for performing appropriate tests of cables determined to have been wetted for a significant period of time. The applicant's July 11, 2002 letter provides a complete revision of the program attributes for the Non-EQ Cable Monitoring program previously provided in the applicant's November 30, 2001, letter. Following are the 10 revised attributes and the staff evaluation of each attribute.

> <u>Scope</u>
>
> Cables that are within the scope of license renewal and subject to aging effects requiring management, but not designated as Environmentally Qualified (EQ), are categorized as three different cable types.
>
> Type E1 includes accessible electrical cables that may experience adverse conditions caused by high values of heat or radiation. Reviews have shown that previously evaluated environments do not cause aging effects requiring management for cable

jackets and connector coverings that are within the scope of licensed renewal. However, since plant conditions can change and create a new possibility for an adverse environment, the applicant plans an additional activity to provide confirmation of these evaluations for the period of extended operation. A detailed review of Surry and North Anna facilities will be performed to determine areas of high temperature or radiation for possible age-related degradation of cable jackets and connector coverings in a potentially adverse environment.

Type E2 cables are used in low-voltage instrumentation loops for high-voltage components such as nuclear instrumentation and radiation monitors. For Surry and North Anna, this situation may lead to aging effects requiring management for the nuclear source, intermediate, and power range instruments. The instrument loops for the source, intermediate, and power range components are susceptible to induced currents from high voltage power supply if insulation resistance diminishes.

Type E3 cables are inaccessible, medium-voltage cables that are energized more than 25% of the time and are potentially exposed to significant moisture (i.e. long term wetting). For Surry and North Anna, this category includes underground cables that supply power to the Reserve Station Service Transformers (RSST). For North Anna only, this category also includes cables supplying power to the service water pump motors. Periodic exposures to moisture lasting less than a few days (e.g., normal rain and drain) do not result in any additional cables being subjected to aging effects requiring management.

Implementation of the Non-EQ Cable Monitoring activities will be completed prior to year 40 of operation.

The staff finds the above acceptable because it appropriately divides the scope of the Non-EQ Cable Monitoring program into three separate categories of cables on the basis of the activities that will be required to manage the aging of each category. It also commits to completing implementation of the Non-EQ Cable Monitoring activities prior to year 40 of operation, in time for the period of extended operation.

Preventive Actions

The Non-EQ Cable Monitoring activities for Type E1 and E2 are designated *condition monitoring.* No preventive actions are performed.

For Type E3 cables, design features that prevent cables from being wetted for significant lengths of time include drains and sump pumps. These features are considered to be preventive actions.

The staff finds the above acceptable because it appropriately identifies the preventive actions necessary to be taken for each category of the Non-EQ Cable Monitoring program identified in the program scope. The Type E1 activity is an inspection activity and no preventative actions are necessary as part of this activity, beyond the inspection activity itself, to prevent or mitigate aging degradation. The Type E2 activity is a surveillance testing program and no preventative actions are necessary as part of this program, outside of the surveillance activity itself, to prevent or mitigate aging degradation. Periodic actions or design features that prevent inaccessible medium-voltage cables (Type E3) from being exposed to significant moisture are considered appropriate because prolonged exposure to moisture and voltage is required to induce the water treeing aging mechanism.

Parameters Monitored or Inspected

For Type E1 cables, an inspection plan will be developed to visually examine representative samples of accessible, non-EQ cable jackets and connector coverings for surface indications such as cracking, discoloration, or bulging. EPRI document TR-109619 will be used for guidance in performing the inspections.

For Type E2 cables, routine calibration tests are performed, based on technical specifications requirements, for indication of possible age-related degradation of insulation that could affect instrumentation loops.

For Type E3 cable, concerns related to water treeing of potentially wetted cables are eliminated by maintaining the cables in a dry condition. Cable manholes will be inspected for water collection.

This attribute is similar to the program attribute immediately below. Additional information on the parameters monitored is also found under the monitoring and trending attribute. The staff finds the information on the parameters monitored acceptable because it includes the parameters that are necessary to be monitored/inspected in order to identify potential aging degradation for each cable type identified as within the scope of the program.

Detection of Aging Effects

For Type E1 cables, visual inspections for representative samples of accessible, non-EQ cable jackets and connector coverings determine the presence of cracking, discoloration, or bulging that would indicate aging effects requiring management. These effects can result from high values of temperature or radiation.

For Type E2 cables, routine calibration tests performed as part of the plant surveillance program will be used to identify the potential existence of age-related degradation.

For Type E3 cables, the environment which could lead to water-treeing in medium-voltage cables will be visually monitored for the presence of water around cables.

The staff finds the above acceptable because it identifies the appropriate means used to identify potential aging degradation for each cable type identified as within the scope of the program. Visual inspection of Type E1 cables has been found to be an acceptable means of identifying potential aging degradation of these cables and connectors. Routine calibration tests for Type E2 cables (source, intermediate, and power range neutron detector cables) are an acceptable means for identifying potential aging degradation of these cables as discussed earlier in this section. Verifying that Type E3 cables (medium-voltage inaccessible cables) are kept dry through periodic inspections for water accumulation is an acceptable means for precluding aging degradation due to water treeing. Cables found to be submerged in standing water will be subject to testing as outlined under acceptance criteria.

Monitoring and Trending

For Type E1 cables, visual inspections for surface anomalies on non-EQ cable jackets and connector coverings can identify indications of age-related degradation due to excessive heat or radiation. Initial visual inspections for representative samples of non-EQ insulated cables and connectors will be performed as a Licensee Follow-up Action between year 30 and the end of the current operating license. Subsequent inspections will be performed at least once per 10 years during the period of extended operation.

For Type E2 cables, routine calibration testing can detect variations on signals in instrumentation loops that are susceptible to induced currents (from high-voltage power supplies) caused by reduced insulation resistance due to aging.

For Type E3 cables, periodic visual inspections for water collection in manholes containing in-scope cables (i.e., the power cables for the service water pump motors at North Anna, and the cables supplying power to the RSST's at Surry and North Anna) will be performed at frequencies ranging from bi-weekly to annually depending upon the design features that exist to mitigate water intrusion into specific manholes.

The staff finds the above acceptable for Type E1 cables and connectors because it commits to initial visual inspection for representative samples of these cables prior to the end of the current operating license and at least once per 10 years during the period of extended operation. This is consistent with the staff position on visual inspections. The Type E2 cables are acceptable because the calibration approach, based on technical specification requirements (see parameters monitored or inspected attribute), is consistent with the staff position. The Type E3 cables are acceptable because manholes containing these cables are periodically inspected for water collection. The staff position on these cable types (medium-voltage inaccessible cables) recognizes that keeping the cables dry through periodic inspections for water accumulation is an acceptable means for precluding aging degradation due to water treeing.

Acceptance Criteria

For Type E1 cables, the acceptance criterion for the condition of accessible, non-EQ cable jackets and connector coverings is the absence of anomalous indications that are signs of degradation. Such indications include cracking, discoloration, or bulging.

For Type E2 cables, acceptance criteria are specified in calibration procedures for source, intermediate, and power range instrumentation. These acceptance criteria are specified in terms of voltage and current limits.

For Type E3 cables, the acceptance criterion with respect to wetted conditions is the absence of exposure to significant wetting. In-scope cable found to be submerged in standing water for an extended period of time will be subject to an engineering evaluation and corrective action. The evaluation will be based on appropriate testing (using available technology consistent with NRC positions) of cables that are determined to be wetted for a significant period of time. The test will use a proven methodology for detecting deterioration of the insulation system due to wetting.

Any anomalies resulting from visual inspections will be dispositioned by Engineering. Occurrence of an anomaly that is adverse to quality will be entered into the Corrective Action System.

The acceptance criterion for Type E1 cables is acceptable because it includes the absence of anomalous indications such as cracking, discoloration, or bulging. This is consistent with staff guidance on this issue. The acceptance criteria for Type E2 cables are acceptable because the acceptance criteria are specified in the calibration procedures for the instrumentation associated with these cables. This is consistent with staff guidance on this issue. The acceptance criterion for Type E3 cables is acceptable because it includes the absence of exposure to significant wetting. The staff has found the applicant's definition of significant wetting is consistent with the terminology "significant moisture" used in the staff guidance for these types of cables. The applicant's acceptance criterion also calls for an evaluation that is based on appropriate testing of cables that are determined to be wetted for a significant period of time. This is consistent with the staff guidance that calls for testing of cables exposed to significant moisture.

Corrective Actions

Corrective actions for conditions that are adverse to quality are performed in accordance with the Corrective Action System as part of the Quality Assurance Program. The engineering evaluation of visual inspection results for the representative samples of accessible cables and connectors will consider whether the observed condition is applicable for other accessible and inaccessible cables and connectors. This engineering evaluation also will consider the potential for moisture in the area of any anomalies. Corrective action for anomalous calibration results for instrumentation loops will lead to adjustments of electronics and may involve component evaluation/replacement. The engineering evaluation of cables found to be wetted for a significant period of time will be based on an appropriate test of the cable and will consider the age, condition, material, and construction of the cables. Testing frequency will be consistent with the guidelines of NUREG-1801 for significantly wetted cables. Any resultant maintenance, repair, or replacement activities will be performed in accordance with the Work Control Process. The corrective action process provides reasonable assurance that deficiencies adverse to quality are either promptly corrected or are evaluated to be acceptable. Where evaluations are performed without repair or replacement, engineering analysis reasonably assures that the component intended function is maintained consistent with the current licensing basis. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined, and an action plan is developed to preclude repetition. The Corrective Action System identifies repetitive discrepancies and initiates additional corrective action to preclude recurrence.

The corrective actions specified for visual inspection results are acceptable because they consider whether the condition observed in the representative sample inspected is applicable to other accessible and inaccessible cables and connectors. The corrective actions further specify that the engineering evaluation will consider the potential for moisture in the area of any anomalies. These corrective actions are consistent with existing staff guidance in this area and the staff finding on low-voltage instrumentation circuits that carry sensitive low-level-signals. The corrective actions specified for anomalous calibration results are acceptable because they include recalibration and potential evaluation and replacement. This is consistent with existing staff guidance. The corrective actions identified for significantly wetted cables are acceptable because they specify that an engineering evaluation, based on test results and other cable parameters, will be performed for these cables. They also indicate that the testing frequency will be consistent with the guidelines of NUREG-1801. These corrective actions are consistent with existing staff guidance on inaccessible medium-voltage cables. The remaining areas of the corrective actions attribute address aspects of the quality assurance program and work control process and are evaluated in Sections 3.3.1.19.2 and 3.3.2 of this SER.

Confirmation Process

The confirmation process for Non-EQ Cable Monitoring involves the Work Control Process to monitor cable conditions on an ongoing basis.

The work control process is evaluated in Section 3.3.1.19.2 of this SER.

Administrative Controls

Administrative and implementation procedures are reviewed, approved, and maintained as controlled documents in accordance with the procedure control process and the Quality Assurance Program.

The quality assurance program is evaluated in Section 3.3.2 of this SER.

Operating Experience

The Non-EQ Cable Monitoring activity is new and has no operating experience. However, the applicant's operating experience has shown that cable jacket anomalies have occurred, and have been evaluated and corrected to maintain intended functions at both Surry and North Anna. Wetted conditions for underground cables also have occurred and corrective actions have been implemented to mitigate the water intrusion.

The staff concludes that the aging management activities identified in the above Non-EQ Cable Monitoring Program should be effective in identifying and correcting the cable jacket anomalies and water intrusion problems identified in the operating experience.

FSAR Supplement

The staff has reviewed the North Anna and Surry revised UFSAR supplements, Section 18.1.4 Non-EQ Cable Monitoring, provided by the applicant in its July 25, 2002 letter (Ref 3.9-13). The staff has confirmed that they contain the applicable elements of the program for non-EQ insulated cables and connectors.

3.9.2.3 Conclusions

On the basis of its review, the staff concludes that the applicant adequately identified the aging effects associated with non-EQ cables and connectors at North Anna and Surry. The staff further concludes that the applicant has demonstrated that these aging effects will be adequately managed so there is reasonable assurance that the components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21 (a)(3).

3.9.3 References for Section 3.9

3.9-1 NRC letter to Virginia Electric and Power Company, dated October 11, 2001, Adams No. ML012860003

3.9-2 NRC Letter to Virginia Electric and Power Company, dated October 22, 2001, Adams No. ML013040164

3.9-3 Virginia Electric and Power Company letter (Serial No. 01-647) to the NRC, dated November 30, 2001

3.9-4 Virginia Electric and Power Company letter (Serial No. 01-685) to the NRC, dated February 1, 2002

3.9-5 NRC telecommunication with Virginia Electric Power Company, dated June 28,2001, Adams No. ML011790454

3.9-6 Sandia Contractor Report SAND96-0344, "Aging Management Guideline for Commercial Nuclear Power Plants-Electrical Cable and Terminations", prepared by Ogden Environmental and Energy Services, Inc., printed September 1996

3.9-7 NRC telecommunication with Virginia Electric and Power Company, dated October 3, 2001, Adams No. ML013020127

3.9-8 Virginia Electric and Power Company letter (Serial No. 01-685A) to the NRC, dated February 1, 2002

3.9-9 *Aging and Life Extension of Major Light Water Reactor Components*, edited by V.N. Shaw and P.E. MacDonald, 1993, Elsevier Science Publishers

3.9-10 Electric Power Research Institute report, EPRI TR-103834-P1-2, "Effects of Moisture on the Life of Power Plant Cables", Part 1, "Medium-Voltage Cables", Part 2, "Low-Voltage Cables", prepared by Ogden Environmental and Energy Services Company, final report, August 1994

3.9-11 Calvert Cliffs Nuclear Power Plant Application for License Renewal, Appendix A, "Technical Information," 6.1, "Cables"

3.9-12 Virginia Electric and Power Company letter (Serial No. 02-297) to the NRC, dated July 11, 2002

3.9-13 Virginia Electric and Power Company letter (Serial No. 02-360) to the NRC, dated July 25, 2002

4.0 Time-limited Aging Analyses

4.1 Identification of Time-Limited Aging Analyses

The applicant described its identification of time-limited aging analyses (TLAAs) in Section 4.1 of the North Anna and Surry LRAs. The staff reviewed this section of each LRA to determine whether the applicant identified the TLAAs as required by 10 CFR 54.21(c).

4.1.1 Summary of Technical Information in the Application

To identify the TLAAs, the applicant evaluated calculations for NAS and SPS against the six criteria specified in 10 CFR 54.3. The applicant indicated that calculations that meet the six criteria were identified by searching the current licensing basis, which includes the UFSAR, engineering calculations, technical reports, engineering work requests, licensing correspondence, and applicable Westinghouse reports. The applicant listed the following TLAAs in LRA Table 4.1-1 for each station:

- reactor vessel neutron embrittlement including analyses for upper shelf energy, pressurized thermal shock, and pressure-temperature limits
- metal fatigue, including analysis of ASME Section III Class 1 components, reactor vessel underclad cracking, and ANSI B31.1 piping (for NAS, the ASME Section III Class 1 component analyses include the reactor coolant pressure boundary; for SPS, the only piping analyses included are for the pressurizer surge lines)
- environmental equipment qualification calculations
- containment liner analyses
- crane load cycle limit
- reactor coolant pump flywheel analysis
- leak-before-break analyses
- spent fuel pool liner analysis
- piping subsurface indication analyses
- reactor coolant pump Code Case N-481 analysis

Pursuant to 10 CFR 54.21(c)(2), the applicant stated that no exemptions granted under 10 CFR 50.12 and based on a TLAA as defined in 10 CFR 54.3 were identified.

4.1.2 Staff Evaluation

As indicated by the applicant, TLAAs are defined in 10 CFR 54.3 as analyses that meet the following six criteria:

- involve systems, structures, and components within the scope of license renewal as delineated in Section 54.4(a)
- consider the effects of aging
- involve time-limited assumptions defined by the current operating term (for example, 40 years)
- were determined to be relevant by the applicant in making a safety determination

- involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in Section 54.4(b)
- are contained, or incorporated by reference in the CLB

The applicant did not identify postulated pipe breaks locations based on the cumulative usage factor (CUF) as a TLAA for either plant. Section 3A.46 of the NAS UFSAR describes the criterion used to provide protection against pipe whips inside the containment. The criterion specifies the postulation of pipe breaks at locations where the CUF exceeds 0.1. Although the applicant identified the fatigue usage factor calculation as a TLAA, the applicant did not identify the pipe break criterion as a TLAA. The usage factor calculation used to identify postulated pipe break locations meets the definition of a TLAA as specified in 10 CFR 54.3. In RAI 4.1-1, the staff requested the applicant to provide a description of the TLAA performed to address the pipe break criterion for NAS. In addition the staff requested the applicant to identify any postulated pipe breaks locations based on CUF at SPS and describe the TLAA performed for these locations.

The applicant's January 16, 2002 response indicated that pipe breaks had been postulated at locations where the CUF exceeds 0.1 at NAS. The applicant also indicated that it did not expect the number of design transients assumed in these CUF calculations to be exceeded in 60 years of plant operation. Therefore, the CUF calculations which form the basis for the NAS pipe break postulations remain valid for the period of extended operation. The applicant's evaluation provides an acceptable TLAA for NAS in accordance with the requirements of 54.21(c)(1). The applicant indicated that the only pipes analyzed to ASME Class 1 rules at SPS are the pressurizer surge lines. The applicant indicated that it did not expect the number of design transients assumed in these CUF calculations to be exceeded during the period of extended operation. Therefore, the SPS pipe break postulations remain valid for the period of extended operation in accordance with the requirements of 54.21(c)(1).

4.1.3 Conclusions

The staff has reviewed the information provided in Section 4.1 of the NAS and SPS LRAs. The NRC staff concludes that, with the inclusion of the pipe break criteria as described above, the applicant has adequately identified the TLAAs as required by 10 CFR 54.21(c), and that no 10 CFR 50.12 exemptions have been granted on the basis of the TLAA as defined in 10 CFR 54.3.

4.2 Reactor Vessel Neutron Embrittlement

The three TLAAs described in Sections 4.2 and A3.1 of the LRAs evaluate the effects of neutron irradiation on the integrity of the reactor vessels. Specifically, they determine the ability of the vessels to (a) maintain acceptable Charpy upper shelf energy (C_VUSE) values during the period of extended operation, (b) resist failure during a pressurized thermal shock (PTS) event, and (c) operate safely using guidance from calculated pressure-temperature (P-T) operating limit curves.

In Section 4.2 of the LRAs, the applicant provides a general overview of its activities to address the three TLAAs mentioned above. The applicant states that it actively participated in the Westinghouse Owners Group (WOG) effort to develop evaluations to demonstrate that the aging effects on reactor vessel (RV) components will be adequately managed during the period of extended operation.

4.2.1 Upper Shelf Energy

4.2.1.1 Summary of Technical Information in the Application

The RV beltline fluences applicable to the postulated 20-year period of extended operating time have been calculated using the NRC-approved Virginia Electric and Power reactor vessel fluence analysis methodology topical report (VEP-NAF-3-A). The methodology therein was stated to be in accordance with Regulatory Guide DG-1053, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." These methodologies were benchmarked using a combination of Dominion surveillance capsule data, RV simulator measurements, and Surry 1 cavity dosimetry measurements.

In LRAs Sections 4.2.1 and A3.1.1, the applicant describes the general procedure for estimating Charpy USE values for the NAS 1/2 and SPS 1/2 RV beltline materials. The USE requirements are included in 10 CFR Part 50, Appendix G, "Fracture Toughness Requirements". One of the requirements is that the licensee must submit an analysis of the fracture toughness at least 3 years before the USE of any of the RV materials drops below 67.8 joules (50 ft-lb). When two or more credible surveillance data sets are available, they may be used to determine the USE of the surveillance material. These data are then used in conjunction with Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Pressure Vessel Materials," to predict the change in the vessel USE due to irradiation.

In the LRA for North Anna, the applicant stated that RV calculations demonstrated that the USE values of limiting RV beltline materials (welds) at the end of the period of extended operation meet Appendix G requirements. On the other hand, for the Surry reactor vessels, compliance with the Appendix G requirements was demonstrated through an equivalent margin analysis. Thus, two different procedures were used for the NAS 1/2 and SPS 1/2 vessels to demonstrate compliance with applicable regulatory requirements.

In an electronic submittal on August 22, 2002 (ADAMS Accession Number ML022670644), and in a letter dated October 15, 2002 (ADAMS Accession Number ML022960411), the applicant submitted supplemental equivalent margin analyses (EMAs) for the Surry 1 and 2 RV beltline materials for which either (1) initial, unirradiated USE values were not known and, hence, for which projected USE values could not be determined at the end of the extended period of operation, or (2) initial, unirradiated USE values was available and the beltline materials' USE at the end of the extended period of operation were projected to fall below the 50 ft-lb criterion specified in Section IV.A.1. of 10 CFR Part 50, Appendix G. The applicant's supplemental EMAs were contained in topical report BAW-2323, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of Surry Units 1 and 2 for Extended Life Through 48 Effective Full Power Years." The applicant's supplemental EMAs demonstrated that, for those Surry 1 and 2 RV beltline materials for which either criterion 1 or 2 above applied, margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code would be maintained through the units' period of extended operation.

4.2.1.2 Staff Evaluation

The staff reviewed the USE evaluations contained in Sections 4.2.1 and A3.1.1 of the LRAs. During the review of the LRAs, the staff found that the information provided is a general description of the procedures for addressing USE concerns. The staff requested that the applicant provide additional information to clarify the procedures used for the North Anna and Surry RVs.

In response to RAI 4.2.1-1, the applicant in a conference call held in October 2001, as documented in its May 22, 2002 letter, stated that the North Anna USE evaluation involved (a) performance of RG 1.99 Revision 2 Position 1.2 USE calculations and (b) comparison of measured and predicted reductions in USE for North Anna 1 and 2 surveillance materials to confirm that Position 1.2 calculations are conservative.

The beltline fluence values were calculated using the NRC-approved Virginia Power reactor vessel fluence analysis methodology. Best-estimate copper content values were determined by averaging the values obtained from original vessel fabrication and surveillance capsule analysis reports. Measured values of the initial USE for each beltline material were obtained from Westinghouse material certification test reports.

Similarly, in response to RAI 4.2.1-2, the applicant stated during the October 2001 conference call that the Surry USE EMA analyses were performed for ASME Levels A, B, C, and D service loadings based on the evaluation acceptance criteria of Section XI, Appendix K. For Levels A and B service loadings, the low upper shelf fracture mechanics evaluation was performed according to the evaluation procedures contained in Section XI, Appendix K. Level C and D service loadings were evaluated using the one-dimensional, finite element, thermal and stress models and linear elastic fracture mechanics methodology of Framatome Technologies' PCRIT computer code to determine stress intensity factors for a worst case pressurized thermal shock transient.

In accordance with 10 CFR Part 50, Appendix G, Section IV.A.1., the following requirement must be met for RV material USE:

> Reactor vessel beltline materials must have Charpy upper-shelf energy, in the transverse direction for base metals and along the weld for weld materials according to the ASME Code, of no less than 75 ft-lb (102 J) initially and must maintain Charpy upper-shelf energy throughout the life of the vessel of no less than 50 ft-lb (68 J), unless it demonstrated . . . that lower values of Charpy upper-shelf energy

will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

By letter dated October 15, 2002, the applicant submitted the neutron fluences for the Surry 1 and 2 and North Anna 1 and 2 RV beltline materials as projected through the expiration of the extended periods of operation for the units. In this letter, the applicant also provided the USE assessments for the limiting USE forging, plate, and weld materials, as projected through the extended periods of operation for the units.

The staff performed independent analyses of the USE TLAAs for the North Anna 1 and 2 and Surry 1 and 2 RV beltline materials. The staff's independent USE analyses were predicated on meeting the USE requirements specified in Section IV.A.1 of 10 CFR Part 50, Appendix G, and were calculated in accordance with the recommended methods of RG 1.99, Revision 2, for determining reductions in USE. For beltline forgings and weld materials represented in the reactor vessel material surveillance programs for North Anna 1 and 2 and Surry 1 and 2 (i.e., surveillance programs implemented in accordance with 10 CFR Part 50, Appendix H), the staff's USE assessments incorporated surveillance data that were derived from the results of Charpy impact tests performed on test specimens removed from pertinent irradiated reactor vessel material surveillance capsules.

With regard to the staff's independent USE analysis for the North Anna 1 and 2 beltline materials, the staff confirmed that the two most limiting beltline forging materials, and the most limiting beltline circumferential weld material were the same as those identified by the applicant for the RVs.[1] Although the staff's calculated USE values for the limiting RV beltline materials were not always consistent with the applicant's calculated USE values, both the staff's and the applicant's USE analyses confirmed that the USE values for the North Anna beltline materials will remain at or above the 50 ft-lb acceptance criteria of 10 CFR Part 50, Appendix G, through the extended periods of operation for the units.

For North Anna 1, the staff determined that the 60-year USE assessment for the RV beltline materials is bounded (limited) by the USE value for lower shell forging 03 (material heat 990400/292332). The staff calculated the projected USE value for lower shell forging 03 to be 55 ft-lb at the end of the extended period of operation for the unit. This material meets the staff's end-of-life 50 ft-lb acceptance criterion for USE. Based on the staff's independent USE calculations for North Anna 1, the staff concludes that the North Anna 1 RV beltline materials will have adequate USE through the extended period of operation for the unit.

For North Anna 2, the staff determined that the 60-year USE assessment for the RV beltline materials is bounded (limited) by the USE value for intermediate shell forging 04 (material heat 990496/292424). The staff calculated the projected USE value for intermediate shell forging 04 to be 50 ft-lb through the expiration of the extended period of operation for the unit. Based on the staff's independent USE calculations for North Anna 2, the staff concludes that the North

1 Since the North Anna RV shells are fabricated from cylindrical forgings, the RV shell designs do not include axial welds. Therefore, for license renewal purposes, the applicant's USE analyses for the North Anna 1 and 2 beltline materials included USE analyses of the two most limiting beltline forgings and the most limiting circumferential weld in each North Anna RV.

Anna 2 RV beltline materials will have adequate USE through the extended period of operation for the unit.

With regard to the staff's independent USE analysis of the RV beltline materials for Surry 1 and 2, the staff confirmed that the most limiting beltline materials were evaluated for compliance with Section IV.A.1 of 10 CFR Part 50, Appendix G, using EMAs. For these RV materials, EMAs were required because either (1) initial, unirradiated USE values were not available for the beltline materials and, hence, projected USE values could not be determined at the end of the extended period of operation, or (2) initial, unirradiated USE values were available and the beltline materials' USE at the end of the extended period of operation was projected to fall below the 50 ft-lb criterion specified in Section IV.A.1 of 10 CFR Part 50, Appendix G.[2]

The NRC staff examined the list of Surry 1 and 2 RV beltline materials for which EMAs analyses were required. Since EMAs require the use of applied loadings in the fracture mechanics analyses, the NRC staff divided the Surry 1 and 2 beltline materials into circumferential and axial welds (between which the loadings due to pressure differ by a factor of two) and sought to identify one bounding axial weld and one bounding circumferential weld for which the NRC staff would perform independent EMAs. Based on information about the beltline materials' best-estimate copper content, projected neutron fluence at the end of the extended period of operation, and initial, unirradiated USE (when available), the NRC staff agreed with the applicant's conclusion that Surry 1 RV lower shell axial weld SA-1526 (weld wire heat 299L44) and Surry 1 RV intermediate-to-lower-shell circumferential weld SA-1585 (weld wire heat 72445) were the bounding beltline materials for the Surry 1 and 2 EMAs.

The NRC staff performed independent an EMAs using the methodologies and models specified in Regulatory Guide 1.161, "Evaluation of Reactor Pressure Vessels With Charpy Upper-Shelf Energy Less Than 50 ft-lb," NUREG/CR-5729, "Multivariable Modeling of Pressure Vessel and Piping J-R Data," and Appendix K to Section XI of the ASME Code, "Assessment of Reactor Vessels With Lower Upper Shelf Energy Charpy Impact Energy Levels." Although the detailed results from the NRC staff's analyses differed from those provided by the applicant in topical report BAW-2323, the NRC staff confirmed the applicant's conclusion that, based on EMAs, the identified Surry 1 and 2 RV beltline materials would have margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code through the units' period of extended operation.

4.2.1.3 FSAR Supplement

Pursuant to the requirements of 10 CFR 54.21(d), the applicant provided a summary description of the TLAA for USE in Section 3.1.1 of the FSAR supplements for Surry 1 and 2 and North Anna 1 and 2. In the FSAR Supplement descriptions for the USE TLAAs, the applicant states that reactor vessel calculations demonstrated that the upper shelf energy values of limiting reactor vessel beltline materials at the end of the period of extended operation

2 The Surry Unit 1 RV materials for which EMAs were required included: nozzle beltline to intermediate shell circumferential weld J726 (weld wire heat 25017), intermediate to lower shell circumferential weld SA-1585 (weld wire heat 72445), lower shell axial welds SA-1526 (weld wire heat 299L44), and lower and intermediate shell axial welds SA-1494 (weld wire heat 8T1554). The Surry Unit 2 RV materials for which EMAs were required included: nozzle beltline to intermediate shell circumferential weld L737(weld wire heat 4275 and lower and intermediate shell axial welds WF-4 (weld wire heat 8T1762).

meet Appendix G requirements and that the TLAA has been projected to the end of the period of extended operation and is adequate. Based on the NRC staff's review of the applicant's USE determination and EMA result, the NRC staff finds the applicant's FSAR supplements statement to be acceptable.

4.2.1.4 Conclusions

The staff has reviewed the TLAA information in Sections 4.2.1 and A3.1.1 of the LRAs, the applicant's responses to RAIs, the applicant's August 22, 2002 electronic submittal, and the supplemental information submitted in the applicant's letter dated October 15, 2002. All these submissions described the applicant's methodology, results, and conclusions regarding the compliance of the North Anna 1 and 2 and Surry 1 and 2 RV beltline materials with the Charpy USE requirements specified Section IV.A.1 of 10 CFR Part 50, Appendix G, though the period of extended operation. Through independent evaluations, the NRC staff confirmed the applicant's conclusion that all North Anna 1 and 2 and Surry 1 and 2 RV beltline materials, through the period of extended operation, would (1) maintain Charpy USE values above 50 ft-lbs, or (2) have margins of safety against fracture equivalent to those required by Appendix G to Section XI of the ASME Code. Therefore, the staff finds that the applicant's TLAA regarding USE for the North Anna 1 and 2 and Surry 1 and 2 RV beltline materials meets the provisions of 10 CFR 54.21(c)(1)(ii).

4.2.2 Pressurized Thermal Shock

4.2.2.1 Summary of Technical Information in the Application

The applicant addressed pressurized thermal shock (PTS) in Sections 4.1.2 and A3.1.2 of the LRAs. The applicant stated that PTS may occur during postulated events such as a loss of coolant accident (LOCA) or a steam line break. The transients that may challenge the integrity of the RV include the following conditions: severe overcooling of the inside surface of the vessel followed by high repressurization; significant degradation of vessel material toughness caused by neutron irradiation; and, the presence of a critical-size defect in the vessel wall. The LRAs note that in 10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events," the NRC established screening criteria for PWR RV embrittlement, as measured by the maximum value of reference temperature (RT_{PTS}) at end-of-life fluence for the limiting beltline materials. RT_{PTS} is the reference temperature for a material's transition from ductility to nil ductility. Screening values were set for beltline axial welds, forgings, or plates, and for beltline circumferential weld seams for plant operation to the end of plant license.

The LRAs state that calculations were performed using the methodology described in an in-house report (VEP-NAF-3-A) to estimate RT_{PTS}. The calculations demonstrated that the limiting beltline materials will be less than the applicable screening criteria established in 10 CFR 50.61 at the end of the period of extended operation. The applicant, therefore, concluded that the TLAA is adequate for the period of extended operation.

4.2.2.2 Staff Evaluation

The staff reviewed the PTS evaluations contained in Sections 4.2.2 and A3.1.2 of the LRAs. The staff requested additional information in order to obtain details of the PTS evaluations for all four reactor vessels. In response to RAI Item 4.2.2-1, the applicant stated during the October 2001 conference call that the beltline fluence values were calculated using the NRC-approved Virginia Power reactor vessel fluence analysis methodology.

By letter dated April 27, 2001, the applicant submitted an update to the NRC's Reactor Vessel Integrity Database (RVID). This submittal included the most recently acquired and analyzed reactor vessel integrity data for North Anna 1 and 2. The applicant submitted a similar update to the RVID for Surry 1 and 2 in November 19, 1999.

In accordance with 10 CFR 50.61(b)(1), the following requirement must be met in order to assure that the RVs for PWR-type light-water reactor facilities will have adequate protection against PTS events:

> For each pressurized water nuclear power reactor for which an operating license has been issued, . . . the licensee shall have projected values of RT_{PTS}, accepted by the NRC, for each reactor vessel beltline material for the EOL fluence of the material.

As established in 10 CFR 50.61(b)(2), the acceptance criteria (screening criteria) are 270 °F for plates, forgings, and axial weld materials and 300 °F for circumferential weld materials.

As established in 10 CFR 50.61(b)(3), the following requirement must be met for evaluating the RT_{PTS} values for the beltline RV materials against the PTS screening criteria:

> For each pressurized water nuclear power reactor for which the value of RT_{PTS} for any material is projected to exceed the PTS screening criterion using EOL fluence, the licensee shall implement those flux reduction programs that are reasonably practical to avoid exceeding the PTS screening criterion . . . .

For applicants applying for renewal of the operating licenses of their PWRs, the projected end-of-life (EOL) neutron fluences for the RV beltline materials are the neutron fluences that are projected for the beltline materials at the expiration of the extended periods of operation for the reactor units.

By letter dated October 15, 2002, the applicant submitted the neutron fluences for the Surry 1 and 2 and North Anna 1 and 2 RV beltline materials as projected through the extended periods of operation for the units. In this letter, the applicant also provided the PTS assessment calculations and RT_{PTS} values for the limiting forging, plate, and weld materials, as projected through the extended periods of operation for the units.

The staff performed independent RT_{PTS} value calculations for the North Anna 1 and 2 and Surry 1 and 2 RV beltline materials, as projected using the neutron fluences for the materials at the expiration of the extended periods of operation for the reactor units. The staff's independent RT_{PTS} value calculations were predicated on meeting the PTS requirements specified 10 CFR 50.61 and were calculated in accordance with the required calculation methods in the rule. For beltline forgings and weld materials represented in the reactor vessel material surveillance programs for North Anna 1 and 2 and Surry 1 and 2 (i.e., surveillance programs implemented in accordance with 10 CFR Part 50, Appendix H), the staff's PTS assessments incorporated surveillance data derived from the results of Charpy impact tests performed on test specimens removed from pertinent irradiated reactor vessel material surveillance capsules.

With regard to the staff's independent PTS analysis for the North Anna beltline materials, the staff confirmed that the two most limiting beltline forging materials and the most limiting beltline circumferential weld material for the North Anna 1 and 2 RVs were the same as those identified by the applicant for the RVs.[3] Although the staff's calculated RT_{PTS} values for the limiting RV beltline materials were not always consistent with the applicant's calculated RT_{PTS} values, both the staff's and the applicant's PTS analyses confirmed that the RT_{PTS} values for the North Anna beltline materials will remain below the screening criteria of 10 CFR 50.61 through the end of the extended operating periods for the units.

For North Anna 1, the staff determined that the 60-year PTS assessment for the RV beltline materials is bounded (limited) by lower shell forging 03 (material heat 990400/292332). The staff calculated the projected RT_{PTS} value for lower shell forging 03 to be 191 °F through the expiration of the extended period of operation for the unit. For North Anna 2, the staff determined that the 60-year PTS assessment for the RV beltline materials is also bounded by lower shell forging 03 (material heat 990533/297335). The staff calculated the RT_{PTS} value for lower shell forging 03 to be 228 °F through the expiration of the extended period of operation for the unit. These materials meet the staff's end-of-life 270°F PTS screening criterion for RV beltline forging materials. Based on these independent calculations, the staff concludes that the North Anna 1 and 2 RVs will have adequate protection against PTS events until the end of the extended periods of operation.

For the Surry 1 limiting weld material, the staff requested additional information from the licensee to: (1) confirm that the neutron fluence methodology applied to the surveillance capsule results and the neutron fluence determinations for the Surry 1 RV beltline materials were consistent with the methodology specified in RG 1.190, and (2) confirm that the use of a chemistry factor from Table 1 in 10 CFR 50.61 was an acceptable basis for calculating the RT_{PTS} value for the axial weld fabricated from weld heat 299L44.

In a letter dated October 15, 2002, the applicant provided updated neutron fluence values that were consistent with the methodology in RG 1.190, and an evaluation of the surveillance data for all surveillance weld material fabricated using weld wire heat 299L44. Applying the criteria and methodology outlined in RG 1.99, Revision 2, the applicant determined that the surveillance data was not credible; therefore, it should not be used to determine the beltline chemistry factor. Instead, the applicant determined the chemistry factor for the Surry 1 beltline weld using the 10 CFR 50.61 Table 1 chemistry factors and provided analyses of the data to confirm this conclusion.

The applicant compared the adjusted increase in transition temperature for each surveillance capsule weld to the predicted value. The adjusted value was determined by normalizing the

3 Since the North Anna RV shells are fabricated from cylindrical forgings, the RV shell designs do not include axial welds. Therefore, for license renewal purposes, the applicant's PTS analyses for the North Anna 1 and 2 beltline materials included PTS analyses of the two most limiting beltline forgings and the most limiting circumferential weld in each North Anna RV. For the Surry RVs, the applicant's PTS evaluations included PTS evaluations of the limiting plate, axial weld, and circumferential weld material in each Surry RV.

measured increase in transition temperature to the average surveillance capsule irradiation temperature and the average surveillance capsule weld chemistry. The predicted value was determined based on the capsule neutron fluence and the average surveillance capsule weld chemistry. The applicant also included an analysis that compared the predicted increase in the transition temperature for each capsule weld based on neutron fluence, percent copper, percent nickel, and the associated 10 CFR 50.61 Table 1 chemistry factors to the measured increase in transition temperature for the capsule weld data. The staff believes this method of analysis is more appropriate for evaluating whether the 10 CFR 60.61 Table 1 chemistry factors should be used to evaluate the beltline welds than the normalization (adjustment) procedure since this method provides a direct comparison of predicted and measured values and the normalization method requires an extrapolation.

Table A identifies all surveillance capsules that contained weld metal fabricated using weld wire heat 299L44. The table identifies the neutron fluence, the percent copper, the percent nickel, the irradiation temperature, the measured increase in transition temperature (ΔRT_{NDT}), the predicted ΔRT_{NDT}, and the measured minus predicted ΔRT_{NDT} values for each capsule weld. The predicted value is the value based on its neutron fluence, percent copper, percent nickel, and the associated 10 CFR 50.61 Table 1 chemistry factors. Table A indicates that all the absolute values of measured minus predicted ΔRT_{NDT} values are less than two standard deviations (2X28 °F=56 °F), except for the Surry-2W1 capsule data. In addition, a few of the measured minus predicted ΔRT_{NDT} values have large positive values.

As a result, the staff performed a statistical analysis of this data to determine whether it was appropriate to utilize the chemistry factor from 10 CFR 50.61 Table 1 and a standard deviation for the shift in transition temperature of 28°F. A z-test was performed on the measured minus predicted ΔRT_{NDT} values listed in Table A. The staff was able to confirm from the results of the z-test that at the 5% significance level that the surveillance data for welds fabricated using weld wire heat 299L44 are consistent with the data used to develop the 10 CFR 50.61 Table 1 chemistry factors. Therefore, based on statistical analysis of the surveillance data, it is appropriate to utilize the chemistry factor from 10 CFR 50.61 Table 1 and the standard deviation for the transition temperature of 28 °F for evaluating the impact of irradiation temperature on welds fabricated using weld wire heat 299L44. Because in its assessment of the Surry 1 beltline weld, which is fabricated from weld wire heat 299L44, the applicant utilized the chemistry factor from Table 1 in 10 CFR 50.61 (PTS Rule) and the standard deviation for the transition temperature of 28 °F, the applicant has acceptably evaluated the impact of irradiation on lower shell axial weld L2.

The staff's independent PTS analysis for the Surry beltline materials confirmed that the most limiting beltline axial weld materials for the Surry 1 and 2 RVs were the same as those identified by the applicant for the RVs. For Surry 1, the staff determined that the 60-year PTS assessment for the RV beltline materials is bounded by lower shell axial weld L2 (weld wire heat 299L44). The staff calculated the RT_{PTS} value for lower shell axial weld L2 to be 268.5 °F through the extended period of operation for the unit. For Surry 2, the staff determined that the 60-year PTS assessment for the RV beltline materials is bounded (limited) by lower shell axial welds L1, L2 and L4 (weld wire heat 8T1762). The staff calculated the RT_{PTS} value for lower shell axial welds L1, L2 and L3 to be 219.2 °F at the end of the extended period of operation for the unit. These materials meet the staff's end-of-life 270°F PTS screening criterion for RV beltline forging materials. Based on the statistical analysis of the surveillance data and its independent calculations, the staff concludes that the Surry 1 and 2 RVs will have adequate protection against PTS events through the extended periods of operation.

4.2.2.3 FSAR Supplement

Pursuant to the requirements of 10 CFR Part 54.21(d), the applicant provided a summary description of the TLAAs for PTS in Section 3.1.2 of the FSAR Supplements for Surry 1 and 2 and North Anna 1 and 2. In the FSAR Supplement descriptions for the PTS TLAAs, the applicant states that the reference temperature for pressurized thermal shock (RT_{PTS}) is defined in 10 CFR 50.61 and that the RT_{PTS} values for the limiting reactor vessel materials at the end of the period of extended operation have been recalculated by the applicant. In the FSAR supplement descriptions for the PTS TLAAs, the applicant also states that, at the end of the period of extended operation, the calculated RT_{PTS} values for the beltline materials are less than the applicable screening criteria established in 10 CFR 50.61; therefore, the TLAA has been projected to the end of the period of extended operation and is found to be adequate.

4.2.2.4 Conclusions

The staff reviewed the TLAA information in the LRA Sections 4.2.2 and A3.1.2, which describe the results for estimating end-of-life RT_{PTS} values for the limiting RV beltline materials and demonstrate that they are below the screening criteria given in 10 CFR 50.61. For the reasons set forth above, the staff concludes that the PTS analyses for the NAS 1/2 and SPS 1/2 RV beltline materials demonstrate that the NAS 1/2 and SPS 1/2 RVs comply with the regulatory screening criteria in 10 CFR 50.61, and that the PTS evaluations for the RV are valid through the extended periods of operation for the Surry and North Anna reactor units and are in compliance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.2.3 Pressure-Temperature Limits

4.2.3.1 Summary of Technical Information in the Application

Sections 4.2.3 and A3.1.3 of the LRAs address pressure-temperature limits for the North Anna 1 and 2 and Surry 1 and 2 reactor vessels. The LRAs include a description of NRC General Design Criteria 14 and 31 which, respectively, specify that there should be an extremely low probability of abnormal leakage (or rapid failure) and of gross rupture in the reactor coolant pressure boundary, and that the pressure boundary should behave in a nonbrittle manner with the probability of rapidly propagating fracture being minimized. The information in the LRAs also includes statements that the heatup and cooldown limit curves are calculated using the most limiting value of the material properties in the beltline vessel region of the reactor vessel. This limiting value is determined by using the unirradiated value for the materials' fracture toughness properties and estimating the shift in the estimated nil-ductility reference temperature ΔRT_{NDT}. From the adjusted reference temperature values, the applicant obtained P-T limit curves in accordance with the requirements of 10 CFR Part 50, Appendix G, "Fracture Toughness Requirements", as augmented by ASME Code Section XI, Appendix G, "Rules for Inservice Inspection of Nuclear Power Plant Components."

The LRAs state that the RV estimated fluence values and beltline material properties at the end of the period of extended operation were used to determine the limiting value of RT_{NDT} using the methods described in Regulatory Guide 1.99, Revision 2. The limiting value of RT_{NDT} was then used to calculate pressure-temperature (P-T) limits that are valid through the period of extended operation. Maximum allowable low-temperature overpressure protection system (LTOPS) power-operated relief valve (PORV) lift setpoints were then developed on the basis of the P-T limits applicable to the period of extended operation. The LRAs state that revised P-T limit curves and LTOPS setpoints will be submitted for review and approval prior to expiration of existing limits, in order to maintain compliance with requirements in Appendix G of 10 CFR Part 50. The applicant concluded that the P-T limits will be maintained during the period of extended operation.

4.2.3.2 Staff Evaluation

The staff reviewed the information in LRA Sections 4.2.3 and A3.1.3, which describe the general procedure for calculating P-T curves for the RV beltline materials through the period of extended operation. This limiting value is stated to be determined by using the unirradiated value for the materials' fracture toughness properties and estimating ΔRT_{NDT}. From the adjusted reference temperature values the applicant obtained P-T limit curves in accordance with the requirements of 10 CFR Part 50, Appendix G, as augmented by ASME Code Section XI, Appendix G. The LRAs also stated that the RV estimated fluence values and beltline material properties at the end of the period of extended operation were used to determine the limiting value of RT_{NDT} using the methods described in RG 1.99, Revision 2. The limiting value of RT_{NDT} was then used to calculate P-T limits that are valid through the period of extended operation.

The applicant also stated that the maximum allowable LTOPS PORV lift setpoints were developed on the basis of the P-T limits applicable to the period of extended operation. Existing technical specification (TS) reactor coolant system P-T limits and the associated LTOPS setpoints are valid to cumulative burnup values (i.e., effective full power years) corresponding to the end of the current license period. The applicant will request that the TS be amended to include revised P-T limit curves and LTOPS setpoints applicable to the period of extended operation, and this request will be submitted for NRC review and approval prior to the expiration of the existing TS limits in order to remain in compliance with the requirements of 10 CFR Part 50, Appendix G. The staff will evaluate the end-of-extended-period-of-operation P-T limit curves for Surry 1 and 2 and North Anna 1 and 2 in accordance with the P-T limit requirements of 10 CFR Part 50, Appendix G, when the applicant submits them for approval pursuant to the license amendment requirements of 10 CFR 50.90.

4.2.3.3 FSAR Supplement

Pursuant to the requirements of 10 CFR 54.21(d), the applicant has provided a summary description of the TLAAs for the Surry 1 and 2 and North Anna 1 and 2 P-T limits in Section 3.1.3 of the FSAR supplements for Surry 1 and 2 and North Anna 1 and 2. In the FSAR supplement descriptions for the TLAAs on the P-T limits, the applicant states, in part, that the RV neutron fluence values corresponding to the end of the period of extended operation and RV beltline material properties were used to determine the limiting value of the reference nil ductility reference temperature (RT_{NDT}), and to calculate RCS P-T operating limits valid through the end of a period of extended operation, and that maximum allowable LTOPS PORV lift setpoints have been developed on the basis of the P-T limits applicable to the period of extended operation. In the FSAR Supplement descriptions for the TLAAs on the P-T limits, the applicant also states, in part, that the revised RCS P-T limit curves and LTOPS setpoints will be submitted for review and approval prior to the expiration of the existing technical specification limits in order to maintain compliance with the governing requirements of 10 CFR Part 50, Appendix G, and that the TLAAs for P-T limits have been projected to the end of the period of extended operation and have been found to be adequate. The staff will evaluate the P-T limits for the extended periods of operation when submitted to the staff for evaluation pursuant to the license amendment requirements of 10 CFR 50.90. Based on these considerations, the staff concludes that the applicant's FSAR supplement summary descriptions for the TLAAs on the P-T limits are acceptable.

4.2.3.4 Conclusions

The staff reviewed the TLAA information in Sections 4.2.3 and A3.1.3 of the LRAs, which describe the applicant's approach in developing the P-T limits for the RV beltline materials. The staff finds that the analyses demonstrate that North Anna and Surry RVs comply with the regulatory requirements in 10 CFR Part 50, Appendix G, and 10 CFR 54.21(c)(1)(ii).

Table A

Surveillance Capsule Irradiation Data Used to Evaluate the Surry 1 Axial Weld Fabricated Using Weld Wire Heat 2994L44

Surveillance Capsule	Neutron Fluence ($x10^{19}$ n/cm^2)	%Copper	% Nickel	Irradiated Temperature (°F)	Measured ΔRT_{NDT} (°F)	Predicted ΔRT_{NDT} (°F)	Measured-Predicted ΔRT_{NDT} (°F)
TMI-2LGI	0.830	0.37	0.70	556.0	216	222	-6
CR-3LGI	0.755	0.36	0.70	556.0	202	212	-10
TMI-2LGI	0.968	0.33	0.67	556.0	226	213	+13
TMI-1C	0.882	0.33	0.67	556.0	166	208	-42
TMI-1E	0.097	0.33	0.67	556.0	74	88	-14
Surry-2WI	0.669	0.36	0.70	546.3	262	205	+57
Surry-IT	0.292	0.23	0.64	533.9	171	117	+54
Surry-IV	1.992	0.23	0.64	538.8	250	209	+41
Surry-IX	1.599	0.23	0.64	542.0	234	199	+35

4.3 Metal Fatigue

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

4.3.1 Summary of Technical Information in the Application

The applicant discussed the criteria used for the design of reactor coolant loop components in Section 4.3.1 of each LRA. The applicant indicated that the reactor vessels, steam generators, pressurizers, reactor coolant pumps, control rod drive mechanisms, and pressurizer surge lines were analyzed using the methodology of the ASME Boiler and Pressure Vessel Code, Section III, Class 1. In addition, the remaining reactor coolant pressure boundary piping, including loop stop valves, of the NAS facility was analyzed using the ASME Code Class 1 methodology. Fatigue analyses were performed for critical locations in these components using conservative assumptions regarding the anticipated plant operational cycles. The applicant stated that a review of the SPS and NAS plant operating histories indicated that the existing design transients and cycle frequencies are conservative and bounding for the period of extended operation. The applicant concluded that, with the exception of the reactor vessel closure studs and the NAS loop stop valves, the existing fatigue analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). The applicant further indicated that the reactor pressure vessel closure studs and the NAS loop stop valves had been reanalyzed and were projected to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

The applicant referenced the Transient Cycle Counting Program (TCCP) as a program that assures the number of cycles does not exceed the design limit during the period of extended operation. The TCCP is described in Appendix B of each LRA.

The applicant discussed the evaluation of reactor vessel underclad cracking in Section 4.3.2 of each LRA. Grain boundary separation perpendicular to the direction of the cladding weld overlay was identified in the heat-affected zone of a European-manufactured reactor vessel base metal in 1971. The acceptability of this condition was demonstrated by a generic fracture mechanics evaluation for the 40-year plant life. The applicant indicated that this evaluation has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

The applicant described the criteria used for the reactor coolant loop piping and balance-of-plant piping in Section 4.3.3 of each LRA. For SPS, this piping, except for the pressurizer surge lines, was designed to the requirements the ANSI B31.1, "Power Piping." For NAS, the reactor coolant pressure boundary piping, including the loop stop valves, was analyzed using the ASME Code Class 1 methodology. The pressurizer surge lines of both stations were designed to the Class 1 requirements of the ASME Code. These lines are covered in the applicant's fatigue assessment discussed in Section 4.3.1 of each LRA. For NAS, the applicant indicated that the balance-of-plant piping was designed to the requirements of ANSI B31.1. The applicant indicated that piping had been evaluated to the requirements of ANSI B31.1 and determined to remain valid for the period of extended operation in accordance with either 10 CFR 54.21(c)(i) or (ii).

In Section 4.3.4 of each LRA, the applicant described the actions taken to address the issue of environmentally assisted fatigue. The applicant described its evaluation of the following fatigue sensitive component locations:

- reactor vessel shell and lower head
- reactor vessel inlet and outlet nozzles
- pressurizer surge line (including the pressurizer and hot-leg nozzles)
- reactor coolant system piping charging nozzle
- reactor coolant system piping safety injection nozzle
- residual heat removal system Class 1 piping

4.3.2 Staff Evaluation

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

The specific design criterion for ASME Class 1 components involves calculating the CUF. The fatigue damage in the component caused by each thermal or pressure transient depends on the magnitude of the stresses caused by the transient. The CUF sums the fatigue damage resulting from each transient. The design criterion requires that the CUF not exceed 1.0. The applicant stated that a review of the NAS and SPS plant operating histories indicated that the number of cycles and the severity of the transients assumed in the design of these components envelops the expected transients during the period of extended operation. In RAI 4.3-1, the staff requested that the applicant provide the following data:

- the current number of operating cycles and a description of the method used to determine the number and severity of the design transients from the operating history
- the number of operating cycles estimated for 60 years of plant operation and a description of the method used to estimate the number of cycles at 60 years
- a comparison of the design transients listed in the UFSAR to the transients monitored by the TCCP as shown in Section B3.2 of each LRA

The applicant's January 16, 2002, response to the staff's RAI indicated that the NAS TCCP has been ongoing since the initial startup of each unit. The SPS TCCP was initiated in January of 2000, and operational data since the initial startup of each unit has been included in the program. The applicant provided comparisons of the number of design transients with the number of transients projected for 60 years of plant operation for each unit in Tables 4.3-1-1 through 4.3-1-4 of the January 16, 2002 letter. The applicant performed a linear extrapolation of the number of operating cycles of most transients to obtain the 60-year estimates. The applicant indicated that the linear extrapolation of the number of heatup, cooldown, and reactor trip transients for SPS was overly conservative because of the large number of these events in the first 10 years of operation. Consequently, the applicant used the most recent 10 years of plant operation as the basis for projecting the future number of cycles of these transients to obtain the 60-year estimates. The staff considers the method described by the applicant to estimate the number of transient cycles for 60 years of plant operation to be reasonable. The applicant's TCCP will continue to track the number of these cycles during the period of extended operation.

The applicant also identified the design transients listed in SPS UFSAR Table 4.1-8 and NAS UFSAR Table 5.2-4 that are not tracked by the TCCP. The applicant indicated that the estimated number of design cycles associated with loading and unloading at 5% of full power was based on the assumption of load-follow operation, whereas the plant is operated in the base-load mode. The staff agrees that the number of design cycles listed in the UFSAR tables for these transients is conservative based on the information presented in NUREG/CR-6260 for an older vintage Westinghouse plant. The applicant also indicated that the hydrostatic test listed in SPS UFSAR Table 4.1-8 is not tracked because no further tests are expected to be performed. The staff finds that the TCCP tracks the significant design transients listed in the UFSARs.

Although the applicant indicated that the existing design transients and cycle frequencies are conservative and bounding for the period of extended operation, the applicant also indicated that the NAS RPV closure studs and RCS loop stop valves were reanalyzed. In RAI 4.3-2, the staff requested that the applicant describe the additional analyses that were required for these components in light of the previous statement that design transients and frequencies are conservative and bounding for the period of extended operation. The applicant's January 16, 2002, response indicated that the RPV closure studs were originally analyzed for 57 events of tensioning and detensioning. The applicant analyzed the closure studs for 200 events of tensioning and detensioning to be consistent with the number of heatup and cooldown cycles. Since the RPV closure studs are not tensioned and detensioned during every heatup and cooldown cycle, the staff considers that this analysis provides a conservative basis for tracking closure stud fatigue based on the number of heatup and cooldown cycles. The applicant also indicated that the RCS loop stop valves were originally analyzed for one steam generator tube rupture event. The applicant indicated that, since there was a tube rupture event at NAS, the analysis was upgraded to include five steam generator tube rupture events. The staff considers the assumption of five steam generator tube events to be conservative.

NRC Bulletin (BL) 88-11, "Pressurizer Surge Line Thermal Stratification," identified a concern regarding potential temperature stratification and thermal striping in the pressurizer surge line. The applicant indicated that the pressurizer surge lines were analyzed in response to the bulletin, and that this analysis considered insurge/outsurge events that were not considered in the original analysis. BL 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," identified a concern regarding the potential for temperature stratification or temperature oscillations in unisolable sections of piping attached to the RCS. In RAI 4.3-3, the staff requested the applicant to describe the actions taken to address BL 88-08 during the period of extended operation. The applicant's January 16, 2002, response to the staff's RAIs indicated that no fatigue calculations had been performed to address BL 88-08. Therefore, no additional actions are required to address this bulletin during the period of extended operation.

The Westinghouse Owners Group (WOG) issued topical report WCAP-14575-A, "License Renewal Evaluation: Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components," to address aging management of the RCS piping. When reviewing the topical report, the NRC staff identified action items for license renewal applicants to take. In Section 3.1.1 of each LRA, the applicant addressed the applicability of WCAP-14575-A to NAS and SPS. Table 3.1.1-W1 of each LRA provides the response to the renewal applicant action items developed during the staff review of the topical report. Renewal Applicant Action Item 8 requests that the applicant address components labeled I-M and I-RA in Tables 3-2 through 3-16 of WCAP-14575. The applicant indicated that the components in Tables 3-2 through 3-16 were addressed by an aging management activity, plant-specific fatigue evaluation, or code evaluation. However, the applicant did not provide details on each component. In RAI 4.3-4, the staff requested the applicant to provide a summary of the resolution of the components labeled I-M and I-RA in Tables 3-2 through 3-16. The applicant's March 27, 2002, supplemental response indicated that the design transients used in the analysis of piping components envelop the projected transients for 60 years of operation. As discussed above, the applicant relies on the TCCP to monitor the number of design transients during the period of extended operation. The staff agrees that the fatigue analyses of these piping components will remain valid if the number of transient cycles assumed in the fatigue analyses is not exceeded during the period of extended operation. The staff review of the TCCP is contained in Section 3.3.3.2 of this SER.

The WOG issued topical report WCAP-14574-A to address aging management of pressurizers. In Section 3.1.4 of each LRA, the applicant discussed the applicability of WCAP-14574-A to NAS and SPS. Table 3.1.4-W1 of each LRA provides the response to the renewal applicant action items developed as a result of the staff's review of the topical report. Renewal Applicant Action Item 1 requests that the applicant demonstrate that the pressurizer subcomponent CUFs remain below 1.0 for the period of extended operation. Table 2-10 of WCAP-14574-A indicates that the ASME Code Section III Class 1 fatigue CUF criterion could be exceeded at several pressurizer subcomponent locations during the period of extended operation. WCAP-14574-A also identified recent unanticipated transients that were not considered in the original ASME Code Section III Class 1 fatigue analyses. In RAI 4.3-5, the staff requested that the applicant provide the following information:

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

The applicant's January 16, 2002, response indicated that plant-specific NAS and SPS analyses were performed based on the recommendations made in WCAP-14574-A. The applicant further indicated that the plant-specific analyses include the effects of all additional transients discussed in WCAP-14574-A that were not considered in the original design. The applicant provided the CLB CUFs applicable through the period of extended operation in Table 4.3-5-1 of its response. These CUFs are all below the ASME Code limit of 1.0 for the period of extended operation.

The CLB CUFs did not include consideration of environmental effects on the fatigue curves. The applicant estimated the maximum effect of environmental fatigue correlations on the pressurizer subcomponent CLB CUFs and presented the results in Tables 4.3-5-1 and 4.3-5-2 of the response. The applicant's evaluation identified that the following subcomponents required further evaluations:

- surge nozzle
- spray nozzle
- lower head and heater well
- upper head and shell
- instrument nozzle

For the analyses of the spray nozzle, lower head and heater well, upper head and shell, and instrument nozzle, the applicant's further evaluation consisted of qualitative discussions of the conservatism. The applicant indicated that the pressurizer spray operates continuously and, therefore, the NAS and SPS pressurizers are not expected to experience the transients that contribute to the high-fatigue usage in the design calculations. The applicant indicated that conservative stress intensification factors were used in the analysis of the lower head and heater well resulted in an artificially high CUF value. The applicant further argued that a detailed finite-element analysis of this sub-component would significantly reduce the calculated CUF. On the basis of the finite-element analyses reported in NUREG/CR-6260, the staff agrees with this qualitative assessment. The applicant's evaluation of the upper head and shell relied on the results of a 1989 Westinghouse study to determine that the pressurizer spray transient does not impinge directly on the upper shell, as assumed in the fatigue analysis. The applicant indicated that the fatigue usage is negligible without direct impingement. The applicant stated that environmental fatigue concerns regarding the instrument nozzle would be bounded by the surge nozzle.

The applicant indicated that the surge-line-to-hot-leg pipe connection is a limiting location from a fatigue perspective for both NAS and SPS when considering reactor water environmental effects. The applicant has committed to additional actions regarding this location during the period of extended operation, as discussed later in this section. The staff considers the surge line a bounding example to represent the effects of the reactor water environment on the fatigue life of pressurizer components during the period of extended operation.

The staff considers the applicant's evaluations a satisfactory method of identifying the most limiting component associated with the pressurizer, the surge line hot-leg nozzle, for further evaluation during the period of extended operation. If further evaluation identifies the need for additional actions for the period of extended operation, then the applicant should reassess the fatigue evaluation of the pressurizer components as part of its corrective action. This reassessment should quantify the conservatism in the analyses as discussed above.

The WOG issued topical report WCAP-14577, Revision 1-A, to address aging management of the reactor vessel internals. Table 3.1.3-W1 of each LRA provides the response to Renewal

Applicant Action Item 11 regarding fatigue TLAA of the reactor vessel internals. Each LRA indicates that the TCCP will assure that the transients will remain within their design values for the period of extended operation. In RAI 4.3-1 the staff requested that the applicant list the transients that contribute to the fatigue usage for each component listed in Table 3-3 of WCAP-14577, Revision 1-A, and discuss how the TCCP monitors these transients. The applicant's January 16, 2002, response indicated that the SPS and NAS internals were designed to the Westinghouse criteria. The applicant further indicated that the Westinghouse criteria contained no TLAAs and that pressure load calculations were performed instead of fatigue calculations. The applicant indicated that the design and design transients for the SPS and NAS internals were similar to those of plants designed to ASME Code Section III Subsection NG criteria. The applicant concluded that the TCCP will monitor the number of design transients to provide reasonable assurance that the design cycles are not exceeded. The implication of the applicant's response is that fatigue of the reactor vessel internals is not a concern for the period of extended operation if the number of transients assumed in the design of other RCS components is not exceeded during the period of extended operation. Since the applicant stated that the design of the SPS and NAS reactor vessel internals did not contain a TLAA, the staff concludes that no TLAA evaluation for the period of extended operation is required by 10 CFR 54.21(c)(1). The aging management of the reactor vessel internals is discussed in Section 3.3.1.15 of this SER.

The applicant indicated that the steam generators, pressurizers, reactor vessels, reactor coolant pumps, CRDMs, and all RCS boundary (NAS) and pressurizer surge lines (SPS) have been evaluated and remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). In addition, the applicant indicated that the reactor vessel closure studs and the NAS loop stop valves had been reanalyzed and projected to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). The applicant further indicated that the TCCP will continue during the period of extended operation and will assure that design cycle limits are not exceeded. The applicant's TCCP tracks transients and cycles of RCS components that have explicit design transient cycles to assure that these components stay within their design basis. Generic Safety Issue (GSI) 166, "Adequacy of the Fatigue Life of Metal Components," raised concerns regarding the conservatism of the fatigue curves used in the design of the RCS components. Although GSI-166 was resolved for the current 40-year design life of operating components, the staff identified GSI-190, "Fatigue Evaluation of Metal Components for 60 year Plant Life," to address license renewal. The NRC closed GSI-190 in December of 1999, concluding:

> The results of the probabilistic analyses, along with the sensitivity studies performed, the iterations with industry (NEI and EPRI), and the different approaches available to the applicants to manage the effects of aging, lead to the conclusion that no generic regulatory action is required, and that GSI-190 is closed. This conclusion is based primarily on the negligible calculated increases in core damage frequency in going from 40 to 60 year lives. However, the calculations supporting resolution of this issue, which included consideration of environmental effects and the nature of age-related degradation, indicate the potential for an increase in the frequency of pipe breaks as plants continue to operate. Thus, the staff concludes that, consistent with existing requirements in 10 CFR 54.21, applicants should address the effects of coolant environment on component fatigue life as aging management programs are formulated in support of license renewal.

The applicant evaluated the component locations listed in NUREG/CR-6260 that are applicable to an older vintage Westinghouse plant for the effect of the environment on the fatigue life of the components. The applicant indicated that the results reported in NUREG/CR-6260 were used to scale up the plant-specific usage factors for the same locations to account for environmental effects. The applicant also indicated that the later environmental fatigue correlations contained in NUREG/CR-6583 and NUREG/CR-5704 were considered in the evaluation. In RAI 4.3-6, the staff requested that the applicant provide the results of the usage factor evaluation for each of the six component locations listed in NUREG/CR-6260. The staff also requested that the applicant discuss how the factors used to scale up the NUREG/CR-6260 usage factors were derived and how the environmental data provided in NUREG/CR-6583 and NUREG/CR-5704 were factored in the evaluations.

In the January, 16, 2002, response, the applicant provided NAS- and SPS-specific usage factors that include environmental effects for the RPV shell at the core support pads and the RPV inlet and outlet nozzles (see Table 4.3-6-2 of the response). The applicant calculated the maximum environmental factor using the equations presented in NUREG/CR-6583 for low-alloy steels in a low-oxygen environment, and applied the factor to the design usage factors at NAS and SPS. The results indicate that the usage factors are less than 1.0. The staff notes that the applicant's assessment of the maximum environmental factors as a function of temperature shown in Tables 4.3-6-2 and 4.3-6-3 is incorrect. The environmental factor should be a constant value for low-oxygen environments. However, since the applicant used the highest calculated environmental factor, the applicant's evaluation is conservative. The staff finds acceptable the applicant's evaluation of the effect of the environment on the RPV shell at the core support pads and the RPV inlet and outlet nozzles.

The applicant used the results presented in NUREG/CR-6260 for an older vintage Westinghouse plant to estimate the impact of the environment on fatigue usage for the charging and safety injection nozzles. The results presented in NUREG/CR-6260 were based on detailed finite-element analyses of the charging and safety injection nozzles at the Turkey Point facility. The staff asked the applicant to discuss the applicability of these detailed finite-element analyses to NAS and SPS. By e-mailed supplemental responses dated March 27 and April 22, 2002, the applicant provided additional detailed technical information to justify using the NUREG/CR-6260 finite-element analyses. The applicant's e-mail response to staff's questions is docketed and available to public. The applicant indicated that no fatigue analysis had been performed for the SPS nozzles. Therefore, the applicant used its assessment of the NAS nozzles to represent the SPS nozzles. The applicant's fatigue analysis of NAS was based on the simplified piping rules. The applicant's assessment of the NAS nozzles consisted of scaling the stresses shown in NUREG/CR-6260 for the ASME Code Section III NB-3600 analysis by a sufficient amount to account for the differences between the design CUF at NAS and the CUF reported in NUREG/CR-6260. That scaling factor was then applied to the detailed finite-element results presented in NUREG/CR-6260 to obtain equivalent stresses for the NAS evaluation. The evaluation involved several qualitative assessments as described below:

- The NAS and SPS nozzles have different thicknesses, different shapes in the transition region, and, in the case of NAS safety injection nozzles, a different nozzle size than the nozzles modeled in NUREG/CR-6260. The applicant argued that these differences have no significant impact on the finite-element analysis results. While the staff agrees that these differences will not have a large impact on the results, it is difficult to quantify the impact of these differences without specific calculations.

- The NAS nozzles do not contain thermal sleeves, whereas the nozzles modeled in NUREG/CR-6260 contain thermal sleeves. The thermal sleeve moderates the impact of thermal shocks in the nozzle bore area. The applicant argues that previous Westinghouse finite-element analyses of nozzles with and without thermal sleeves have demonstrated that the critical location remains at the nozzle-to-pipe weld upstream of the thermal sleeve. The applicant further argues that the NUREG/CR-6260 analyses will provide conservative results because the thermal sleeve creates a temperature discontinuity that is not present in the NAS nozzles. The staff does not have sufficient information to make a judgment on this issue. The applicant's supplemental responses do not indicate whether the thermal sleeve design used in the Westinghouse analysis is the same as the thermal sleeve design in the NUREG/CR-6260 analysis. It would be easier to judge the assessment of the environmental effects on the NAS nozzles, if the applicant based its assessment directly on the Westinghouse finite-element analyses.

- The applicant did not use the strain rates used in NUREG/CR-6260 to obtain the environmental adjustment factors. Instead, the applicant used a methodology from the published literature to estimate strain rates. These estimated strain rates are much higher than the strain rates used in the NUREG/CR-6260 evaluations. The impact of using the higher strain rates is to obtain a much lower value for the environmental correction factor than would be obtained using the strain rates used in the NUREG/CR-6260 evaluations. On the basis of the discussion in Section 3.4 of NUREG/CR-6260, the staff considers the strain rate estimate of 1.23%/sec for the safety injection nozzle to be unrealistically high.

On the basis of the above discussion the staff identified the evaluation of the charging and safety injection nozzles as Open Item 4.3-1 in the SER with open items, dated June 2002. The staff requested that the applicant provide an assessment of these nozzles that is directly applicable to NAS and SPS.

The applicant provided an additional assessment of the NAS charging and safety injection nozzles in a June 13, 2002, submittal. The applicant employed finite-element models of the NAS charging and safety injection nozzles to obtain the stresses for the various design load conditions, including thermal transients. The applicant indicated that the stress for each load was calculated separately and the results combined in a conservative manner. The calculated fatigue usage included the effect of the environment. The applicant indicated that the most limiting location for both nozzles is the safe end region. Although the reported CUFs are below the ASME limit of 1.0, the applicant used an adjusted environmental correction factor to compute the CUF. The adjusted environmental correction factor credits the current ASME fatigue curves for accounting for moderate environmental effects. The adjusted environmental correction factor is calculated by dividing the environmental correction factor obtained using equations provided in NUREG/CR-6583 and NUREG/CR-5704 by a Z-factor. The environmental correction factor is the ratio of the fatigue life in air (basis of the ASME fatigue curves) to the fatigue life in the reactor water environment. The Z-factor is the credit taken in the ASME design curves to account for moderate environmental effects. The staff identified technical issues regarding the use of the Z-factor in a June 26, 2002 letter to the Nuclear Energy Institute regarding the staff review of EPRI Technical Report, "Guidelines for Addressing Fatigue Environmental Effects in a License Renewal Application (MRP-47)." As a consequence, the staff does not currently endorse the use of the Z-factor.

The applicant's October 1, 2002, response to the staff committed to manage the environmental fatigue of the charging and safety injection nozzles for NAS and SPS using one or more of the following options prior to the period of extended operation:

1. further refinement of the fatigue analyses to lower the CUFs to below 1.0
2. repair of the affected locations
3. replacement of the affected locations
4. manage the effects of fatigue by an inspection program that has been reviewed and approved by the NRC (e.g., periodic nondestructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC)

The applicant indicated that, if the fourth option is selected, the inspection details, including scope, qualification, method, and frequency, will be provided to the NRC for review and approval prior to the period of extended operation. An aging management program under this option would be a departure from the design basis CUF evaluation, described in the UFSAR supplements and, therefore, would require a license amendment pursuant to 10 CFR 50.59. In view of the above, the staff finds the applicant's proposed program to be an acceptable plant-specific approach to address environmentally assisted fatigue during the period of extended operation in accordance with 10 CFR 54.21(c)(1). On the basis of the above discussion, the staff considers open item 4.3-1 closed.

The applicant evaluated the NAS RHR tee location using the stainless steel environmental fatigue correlation provided in NUREG/CR-5704. The applicant applied the environmental factor applicable to temperatures less than 200 °C to the NAS calculated design value. The applicant indicated that the temperatures for the controlling RHR transient are less than 200 °C. The applicant's evaluation of the effect of the environment on fatigue indicates a usage factor less than 1.0. The applicant indicated that no fatigue calculations were performed at this location for SPS. The applicant indicated that the geometry and material of the RHR tee at SPS are similar to those at NAS. The applicant further indicated that the transient stresses are expected to be similar in NAS and SPS. On the basis of the applicant's assertion that the RHR tees at NAS and SPS are similar, the staff considers the applicant's evaluation of NAS adequate to represent SPS for fatigue evaluation.

The applicant indicated that the pressurizer surge line required further evaluation for environmental fatigue during the period of extended operation. The applicant further indicated that it would use an aging management program to address fatigue of the surge line during the period of extended operation. The aging management program would rely on augmented inspections to address surge line fatigue during the period of extended operation. As indicated in the safety evaluation for WCAP-14575-A, the NRC has not endorsed a procedure on a generic basis which allows for ASME Section XI inspections in lieu of meeting the fatigue usage criteria. In RAI 4.3-7, the staff requested that the applicant provide a detailed technical evaluation which demonstrates the proposed inspections provide an adequate technical basis for detecting fatigue cracking before such cracking leads to through-wall cracking or pipe failure. The staff indicated that, as an alternative to the detailed technical evaluation, the applicant could provide a commitment to monitor the fatigue usage, including environmental effects, during the period of extended operation and to take corrective actions, as approved by the staff, if the usage is projected to exceed 1.0.

The applicant's January 16, 2002, response indicated that the surge line weld at the hot-leg pipe connection will be included in an augmented inspection program. The applicant further indicated the results of these inspections and the results of planned research by the EPRI-sponsored Materials Reliability Program (MRP) will be utilized to assess the appropriate approach for addressing environmentally assisted fatigue of the surge lines. The applicant indicated that the approach developed could include one or more of the following:

1. further refinement of the fatigue analysis to lower the CUF(s) to below 1.0
2. repair of the affected locations
3. replacement of the affected locations
4. manage the effects of fatigue by an inspection program that has been reviewed and approved by the NRC (e.g., periodic nondestructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC)

The applicant indicated that, if the fourth option is selected, the inspection details, including scope, qualification, method, and frequency, will be provided to the NRC for review and approval prior to the period of extended operation. An aging management program under this option would be a departure from the design basis CUF evaluation, described in the UFSAR supplements and, therefore, would require a license amendment pursuant to 10 CFR 50.59. In view of the above, the staff finds the applicant's proposed program to be an acceptable plant-specific approach to address environmentally assisted fatigue during the period of extended operation in accordance with 10 CFR 54.21(c)(1).

ANSI B31.1 requires that a reduction factor be applied to the allowable bending-stress range if the number of full-range thermal cycles exceeds 7,000. The applicant indicates that its review of plant operating practices found that most B31.1 systems operate continuously in a steady state and are only subjected to plant heatup and cooldown cycles. Therefore, the applicant concluded that the analyses of these piping components remained valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). However, the applicant indicated that the NAS hot- and cold-leg sample lines will be subjected to greater than 7,000 cycles during the period of extended operation. The applicant indicated that an evaluation considering stress range reduction factors demonstrates that these lines are qualified for 22,500 cycles, which exceeds the number of cycles expected during the period of extended operation. Therefore, the applicant concluded that these analyses had been evaluated and determined to remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii). The staff found the applicant's evaluation acceptable.

The applicant indicated that a generic evaluation of underclad cracks had been extended to 60 years using fracture mechanics evaluations based on a representative set of design transients with the occurrences extrapolated to cover 60 years of service. The applicant indicated that this generic analysis is documented in WCAP-15338, "A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants (MUHP-6110)," which was submitted by the WOG by letter dated March 1, 2001. This report describes the fracture mechanics analysis the impact of 60 years of operation on reactor vessel underclad crack growth and reactor vessel integrity. The pressurized-thermal-shock portion of the analysis applies to three-loop Westinghouse plants. Since NAS and SPS are three-loop plants, the staff considers the analysis applicable to NAS and SPS. The staff's October 15, 2001, safety evaluation of WCAP-15338 identified two renewal applicant action items to be addressed in the plant-specific license renewal application when incorporating the WCAP-15338 report in a renewal application. The first renewal action item requires the license renewal applicant to verify that its plant is bounded by the WCAP-15338 report (e.g., to verify that the number of design cycles and transients assumed in WCAP-15338 bounds 60 years of operation of the three-loop plant). The applicant indicated that the plant-specific design transients are bounded by the representative set used in the WCAP-15338 evaluation. The second renewal action item requires that the license renewal applicant referencing WCAP-15338 for RPV components provide a summary description of the TLAA evaluation in the FSAR supplement. The applicant's July, 25, 2002, response, provided a revised UFSAR supplements for NAS and SPS which referenced WCAP-15338. The staff found the applicant's TLAA evaluation of underclad cracking acceptable in accordance with the requirements of 10 CFR 54.21(c)(1).

4.3.3 FSAR Supplement

The applicant's FSAR supplement for metal fatigue is provided in Section A3.2 of each LRA. The applicant describes the TLAA evaluations and the TCCP. Open item 4.3-2 indicated that the applicant should update the FSAR supplement to provide a more detailed discussion of its proposed program to address environmental fatigue effects. The applicant provided a discussion of its evaluation of its evaluation of environmentally assisted fatigue in Section 18.3.2.4 of the revised UFSAR supplements for NAS and SPS. The applicant's revised UFSAR supplements for NAS and SPS contains a discussion of the proposed approach to manage environmentally assisted fatigue for the surge line hot-leg pipe connection and the safety injection and charging nozzles. As discussed in Section 4.2.2 of this SER, additional inspection is one of the alternative methods proposed for addressing environmental fatigue of the surge line hot-leg connection, safety injection, and charging nozzles. The applicant provided a further discussion of its proposed augmented inspection plan for the pressurizer surge line hot-leg nozzle in Section 18.2.1 of the revised UFSAR supplements for NAS and SPS. If the applicant selects the inspection option to manage environmentally assisted fatigue, the inspection details must be submitted to the staff prior to the period of extended operation and the method must be accepted by the staff. The applicant indicated that the inspection details regarding scope, frequency, qualifications, methods, etc., will be submitted to the NRC. On the basis of the applicant's revised UFSAR supplement, as clarified above, the staff considers this part of open item 4.3-2 closed.

The applicant provided a summary description of the reactor vessel underclad cracking TLAA in Section A3.2.2 of the UFSAR supplement. The summary description did not reference WCAP-15338. Open item 4.3-2 also indicated that the applicant should include a reference to the WCAP-15338 evaluation in the UFSAR description to provide the technical basis for the TLAA evaluation. The applicant included the reference to WCAP-15338 in its updated UFSAR supplement for both NAS and SPS. Therefore, this part of open item 4.3-2 is closed.

On the basis of its review of the Section 18.3.2 of the revised UFSAR supplements for NAS and SPS, the staff concludes that the UFSAR supplements contain a summary description of the evaluation of time-limited aging analysis as required by 10 CFR 54.21(d).

4.3.4 Conclusions

On the basis of its evaluations of NAS and SPS components, the applicant concluded that the fatigue analysis of RCS components and B31.1 piping remains valid for the period of extended operation. In addition, the applicant has projected the reactor vessel underclad cracking analysis to a 60-year period of operation. The applicant also has a TCCP to maintain a record of the transients used in the fatigue analyses of RCS components, and that process will continue during the period of extended operation. The staff concludes the applicant's actions and commitments satisfy the requirements of 10 CFR 54.21(c)(1).

4.4 Environmental Qualification of Electric Equipment

The NAS 1/2 and SPS 1/2, 10 CFR 50.49 Environmental Qualification (EQ) Program, has been identified as a time-limited aging analysis (TLAA) for the purpose of license renewal. The EQ Program is applicable to the following equipment:

- safety-related electrical and electronic equipment that is relied on to remain functional during and following a design basis accident
- non-safety-related electric equipment whose failure under postulated environmental conditions could impede a safety function
- certain necessary post-accident monitoring equipment

The staff has reviewed NAS and SPS LRA Section 4.4, "Environmental Qualification of Electric Equipment," to determine whether the applicant has demonstrated compliance with the requirement for TLAAs set forth in 10 CFR 54.21(c)(i) for environmentally qualified SCs. The staff also reviewed the following EQ guidance documents, as applicable: RG 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Rev. 3, Information and Enforcement Bulletin (IEB) 79-01B, "Environmental Qualification of Class 1E Equipment," and NUREG-0588 (Category II), "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment."

4.4.1 Summary of Technical Information in the Application

In Section 4.4 of each LRA, the applicant describes its TLAA evaluation for EQ components. In this description the applicant states that the TLAAs for EQ components were evaluated in accordance with 10 CFR 54.21(c)(1), Option iii. The applicant credits its EQ Program, as described in each LRA, Appendix B, Section B3.1, to meet the demonstration required by Option iii. Therefore, the applicant is required to demonstrate that the effects of aging on the intended functions of EQ components will be adequately managed for the period of extended operation through analysis, testing, refurbishment, or replacement.

In accordance with 10 CFR 50.49, aging analyses were developed to establish the qualified life of the EQ equipment. In each LRA, Section 4.4, the applicant concludes that the aging analyses that are based on, or developed for, the current operating term (typically 40 years) or longer are considered to be TLAAs for the purpose of license renewal. Equipment with a qualified life of less than the current operating term is not within the scope of license renewal for the purpose of TLAAs in accordance with the definition of TLAA in 10 CFR 54.3(a)(3),

In Section 4.4 of each LRA, the applicant states that the EQ equipment is identified in the Equipment Qualification Master List (EQML). This list also establishes the "equipment end-of-life date" and references the applicable qualification documentation review (QDR). The QDR contains pertinent information on qualified life and applicable environmental parameters.

Between the two applications, the applicant identified 68 component groups from the EQML that have a qualified life based on the current operating term or longer and that need to be considered under 10 CFR 54.21(c)(1).

The applicant also identifies the following corporate technical standards that are used in the implementation of its EQ Program:

- personnel responsibilities
- program methodology
- eq program maintenance
- environmental zone descriptions
- environmental qualification master list
- qualification document reviews

In addition, the applicant states that its EQ Program covers procurement, design changes, upgrades and repairs, plant operating changes, basis calculations, temperature, radiation, ventilation, industry operating experience, and document control.

The applicant states that the environmental qualification calculations (for the 50 component groups that meet the definition of a TLAA) are the technical rationale for determining the current licensing basis as it applies to the current operating term. The applicant also states that the environmental qualification calculations will be used to determine the qualification of the EQ components for the period of extended operation. When aging analysis cannot demonstrate a qualified life into the period of extended operation through reevaluation, the component and/or part will be replaced before it exceeds its qualified life in accordance with the EQ Program.

The applicant describes its process for reevaluating the qualified life of EQ equipment using the environmental service conditions that are applicable to the equipment. The environmental service conditions are divided into normal and accident service conditions. Section 50.49 of 10 CFR requires that all significant aging effects from normal service conditions be considered. This would include the expected thermal aging effects from normal temperature exposure, any radiation effects during normal plant operation, and mechanical cycle aging as applicable. Section 50.49 of 10 CFR also requires evaluation of the effects of any harsh environments the equipment could be exposed to under accident conditions.

The description provided by the applicant of its reevaluation of normal service conditions is as follows:

- <u>Thermal-Aging Considerations</u> - The specific analyses for thermal aging were reviewed by the applicant to confirm that the existing calculations would remain valid or could be projected to encompass the extended period of operation. Under a plant modification some components were installed which will not experience 60 years of thermal aging by the end of the period of extended operation.
- <u>Radiation Considerations</u> - The total integrated dose (TID), or bounding dose, for the 60-year period, was determined by adding the accident dose to the newly determined 60-year normal dose for the device. The normal dose for the extended period of operation (60 years) was obtained by multiplying the current 40-year normal operating dose by 1.5 (i.e., 60 years/40 years =1.5). The TID was compared to the qualification level to provide reasonable assurance that the required TID would be met or enveloped.

  If the TID calculated by this method is higher than the qualification value, the component group or part will be assessed prior to the end-of-life date.

- Mechanical-Cycle Considerations - The applicant made an assumption that the normal cycles for the period of extended operation would be 1.5 times (i.e., 60 years/40 years = 1.5) the established cycles for the 40-year period. If the number of cycles by this method is higher than the qualification value, the component group or part will be assessed by the applicant prior to its end-of-life date as per the EQ Program requirements.

In summary, under the EQ Program, the Qualification Documentation Review (QDR) or the reevaluation of the qualified life of EQ equipment will be used to demonstrate that the effects of aging on the intended functions will be adequately managed for the period of extended operation on the basis of the qualification levels of each aging category (i.e., thermal, radiation, and mechanical cycles). When aging analysis cannot justify a qualified life into the period of extended operation, then the refurbished component and/or part will be replaced prior to exceeding its qualified life in accordance with the EQ Program.

4.4.2 Staff Evaluation

In accordance with 10 CFR 54.29, the staff has reviewed the NAS and SPS LRAs, Section 4.4, "Environmental Qualification of Electric Equipment," and Appendix B, Section B3.1, "Environmental Qualification Program," to determine whether the applicant had demonstrated compliance with the requirement set forth in 10 CFR 54.21(c)(i) for EQ components. The staff also reviewed the following EQ guidance documents (as applicable): RG1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants To Assess Plant and Environs Conditions During and Following an Accident," Rev. 3, Information and Enforcement Bulletin (IEB) 79-01B, "Environmental Qualification of Class 1E Equipment," NUREG-0588 (Category II), "Interim Staff Position on Environmental Qualification of Safety-related Electrical Equipment," and the NRC guidance for addressing GSI-168 for license renewal as contained in a letter to NEI dated June 2, 1998.

In each LRA, Section 4.4, the applicant states that the EQ equipment is identified in the Equipment Qualification Master List (EQML), which also contains the end-of-life date for each component. Between the two applications, the applicant identified 68 component groups from the EQML that have a qualified life based on the current operating term or longer and that need to be considered under 10 CFR 54.21(c)(1). Equipments with a qualified life of less than the current operating term were not within the scope of this analysis. A list of EQ equipment, such as the EQML, is required under 10 CFR 50.49(d), along with the related information described by the applicant in Section 4.4 of each LRA. This list has been verified by the staff during inspection activities to establish compliance with 10 CFR 50.49 and, therefore, is accepted for the purpose of this review. The applicant's determination to include all EQ equipment whose qualified life is based on the current operating term or longer (and to exclude equipment with a shorter qualified life) is consistent with 10 CFR 54.21(c)(1) and the definition of a TLAA as defined under 10 CFR 54.3. The staff reviewed the list of components and the requirements cited above, and did not identify any omission in the scope of EQ equipment selected by the applicant in accordance with 10 CFR 54.21(c)(1).

The applicant chooses to demonstrate that the effects of aging on the intended functions of EQ components will be adequately managed for the period of extended operation consistent with 10 CFR 54.21(c)(1), Option iii, and credits its EQ Program, as described in each LRA, Appendix B, Section B3.1, as a means of fulfilling this requirement. Option iii is allowed under

10 CFR 54.21(c)(1) and is therefore acceptable to the staff. The staff's review and evaluation of the overall aging management program elements of the EQ Program is provided in Section 3.3.3.1 of this SER. The rest of this SER section documents the staff's review and evaluation of the applicant's reevaluation methodology of the qualified life for EQ components that are in the scope of this TLAA, the predominant approach expected to be used by the applicant.

In a letter to the NRC dated November 30, 2001, the applicant described its reevaluation approach. The applicant states that conservatism may exist in aging evaluation parameters (such as the assumed ambient temperature of the component or an unrealistically low activation energy) or in the operating parameters of a component (e.g., deenergized versus energized). The reevaluation of an aging analysis to extend the qualified life of a component normally reduces the excess conservatism incorporated in the prior evaluation or demonstrates that the existing qualification parameters envelop the requirements for the period of extended operation. As part of the applicant's EQ Program, reevaluation of an aging analysis to extend the qualified life of a component is performed in accordance with 10 CFR 50.49(e). While a life-limiting component condition may be due to thermal, radiation, and/or mechanical: cycle aging; the vast majority of life-limiting conditions for EQ components are based, at least in part, on thermal conditions.

In addition, the applicant states that the reevaluation of an aging analysis is documented in accordance with its Quality Assurance Program, which requires verification of assumptions and conclusions. Important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). These attributes are discussed in the following paragraphs.

<u>Analytical Methods</u>. The applicant states that its reevaluation of aging analysis for the purpose of license renewal uses the same analytical models used in determining its CLB under 10 CFR 50.49. The Arrhenius methodology is the thermal model accepted by the staff for performing its current thermal aging analyses. The analytical method used by the applicant for radiation aging analysis demonstrates qualification for the total integrated dose; that is, the normal radiation dose for the projected installed life plus the accident radiation dose. The staff accepted this approach for the current operating term of 40 years. For license renewal the applicant stated that it would be establishing the 60-year normal radiation dose by multiplying the 40-year dose by 1.5 (60 years/40 years = 1.5). The 60-year normal radiation dose will be added to the accident radiation dose to obtain the total integrated dose for each applicable component. A similar approach will be used for cyclical aging. The staff determined that the applicant's approach for thermal, radiation, and cyclical aging to be consistent with the NAS and SPS CLB, and can be effective in determining the added aging for the period of extended operation

<u>Data Collection and Reduction Methods</u> - The applicant states that reduction of excess conservatism in component service conditions (e.g., temperature, radiation, cycles) that was used in its prior aging analyses is the primary method that will be used for re-evaluating the qualified life for the period of extended operation, and will be implemented based on its EQ Program procedures. Temperature used in an aging evaluation should be conservative, and based on plant design and actual plant temperature data. Plant temperature data may be used in an aging evaluation:

- to determine the temperature service condition and directly apply the plant temperature data in an aging evaluation or

- to demonstrate conservatism when using the plant design temperature for an evaluation

Changes to material activation energy values as part of a reevaluation are to be justified on a component/materials-specific basis. Similar methods of reducing excess conservatism in the component service conditions used in prior aging evaluations can be used for radiation and cyclical aging.

The staff reviewed the applicant's data collection approach and found it to be conservative and bounding. The applicant used a good cross-section of plant environments over a 60-year period allowing for a cross-section of ambient conditions. The elimination of excessive conservatism is consistent with 10 CFR 50.49 and industry practices. In addition, the reduction method described by the applicant is also consistent with industry practices and, therefore, is acceptable to the staff. The staff also agrees changes to material activation energy values need to be determined on a component/material-specific basis.

Underlying Assumptions - The applicant states that EQ component aging evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant modifications and events. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. These events, and the applicant's evaluation and corrective actions, are typically reviewed by the staff and, therefore, are acceptable for the purpose of license renewal.

Acceptance Criteria and Corrective Action - The applicant states that under its EQ Program, the reevaluation of an aging analysis could extend the qualification of a component. If the qualified life of a component cannot be extended by reevaluation, the component must be refurbished, replaced, or requalified by testing before exceeding the period for which the current qualification remains valid. Reevaluations must be performed in a timely manner; that is, the reevaluation must be completed with sufficient time available to refurbish, replace, or requalify the component prior to exceeding its qualified life if the reevaluation is unsuccessful.

4.4.3 Conclusion

On the basis of the review described above, the staff has determined that there is reasonable assurance that the applicant has adequately identified the TLAA for the EQ components as defined in 10 CFR 54.3. On the same basis and on the basis of the staff's review of the EQ Program, as documented in Section 3.3.3.1 of this SER the staff finds that the applicant has demonstrated, with reasonable assurance, that the effects of aging on the intended functions of these components will be adequately managed for the period of extended operation.

4.5 Containment tendon Loss of Prestress

Not applicable to North Anna or Surry plants. The NAS 1/2 and SPS 1/2 containments utilize a reinforced concrete design without the use of prestressed tendons. Therefore, loss of prestress is not applicable for the containments.

4.6 Containment Liner Plate

The applicant described its evaluation of the containment liner plate, metal containment, and penetration fatigue analyses in Section 4.6 of each LRA. The staff reviewed this section of each LRA to determine whether the applicant had evaluated the TLAAs in accordance with 10 CFR 54.21(c).

4.6.1 Summary of Technical Information in the Application

The applicant indicated that fatigue of the liner plate was evaluated in accordance with paragraph N-415 of Section III of the ASME Code, 1968 edition. The fatigue design of the containment liner plate for both stations was based on the following load conditions:

- 1,000 cycles of operating-pressure variations
- 4,000 cycles of operating-temperature variations
- 20 design basis earthquake cycles

Although the applicant indicated that the number of anticipated thermal and pressure variations expected during the 40-year design life of the plant is much less than the number assumed in the design, the applicant multiplied the existing design cycles by a factor of 1.5 to evaluate the containment liner plate for the period of extended operation. The applicant further indicated that the evaluation included the effects of containment Type A pressure tests. The applicant indicated that the revised containment liner fatigue analysis is projected to remain valid for the period of extended operation, in accordance with 54.21(c)(1)(ii).

The applicant indicated that there are no TLAAs for containment penetrations. The applicant further indicated that the penetrations were designed for a one-time load due to collapse of the connecting piping. The applicant also indicated that each unit has a concrete containment with a metal liner and, therefore, metal containment fatigue analysis is not applicable to NAS or SPS.

4.6.2 Staff Evaluation

The design of the SPS liner plate and penetrations is described in Section 15.5.1.8 of the SPS UFSAR. The UFSAR indicates that the SPS containment liner is designed for 1,000 cycles of operating-pressure variations, 4,000 cycles of operating-temperature variations, and 20 design basis earthquakes, all simultaneously applied. The design of the NAS linear plate and penetrations is described in Section 3.8.2 of the NAS UFSAR. Table 3.8-7 indicates that the NAS containment liner is designed to 100 cycles of operating-pressure variations, 400 cycles of operating-temperature variations, and 20 design basis earthquake cycles. The applicant indicated that the number of temperature and pressure variations at NAS is expected to be less than these values for 40 years of plant operation. However, the staff notes that the NAS LRA states that the liner plate is designed for 1,000 cycles of operating-pressure variations, 4,000 cycles of temperature variation, and 20 design basis earthquakes, all simultaneously applied. In open item 4.6-1, the staff requested that the applicant resolve the discrepancy in the NAS design. The applicant's July 25, 2002, response to open item 4.6-1 indicated that the same number of cycles was used for the design of the NAS and SPS liner plates as stated in the LRA. The applicant explained that cycles listed in Table 3.8-7 of the NAS UFSAR were anticipated cycles and not design cycles. The applicant indicated that a revision of NAS

UFSAR Table 3.8-7 would be implemented to clarify the number of cycles used in the design of the liner plate. The applicant's clarification resolves the open item 4.6-1.

The applicant has evaluated both the NAS and SPS containment liner plates using a conservative estimate of the number of expected pressure and temperature cycles for the period of extended operation. This estimate includes 1500 cycles of operating-pressure variations, 6000 cycles of operating-temperature variations, and 30 design basis earthquake cycles. On the basis of its previous license renewal reviews, the staff agrees that the applicant has performed a conservative evaluation of the number of design cycles for the period of extended operation. The staff found the applicant's TLAA for the containment liner plate acceptable in accordance with the requirements of 10 CFR 54.21(c)(1).

4.6.3 FSAR Supplement

The applicant's FSAR supplement, provided in Section A3.4 of each LRA, did not indicate that a fatigue evaluation assuming 1.5 times the number of design cycles was used to demonstrate that the fatigue evaluation of the liner plate remained valid for the period of extended operation. In open item 4.6-2, the staff requested that the applicant revise the FSAR supplement to describe the TLAA evaluation of the containment liner plate, including the number of design cycles used for the evaluation of each facility. The applicant provided a discussion of the TLAA performed for the containment liner plate, including the number of cycles used for the evaluation of each facility, in Section 18.3.4 of the revised UFSAR supplements for NAS and SPS. The applicant's revised UFSAR supplements resolves open item 4.6-2.

On the basis of its review of the Section 18.3.4 of the revised UFSAR supplements for NAS and SPS, the staff concludes that the UFSAR supplements contain a summary description of the evaluation of time-limited aging analysis as required by 10 CFR 54.21(d).

4.6.4 Conclusions

The staff concludes the applicant's evaluation of the containment liner plate satisfies the requirements of 10 CFR 54.21(c)(1).

4.7 Other Time-limited Aging Analyses

The applicant described its evaluation of the Crane Load Cycle, RCP Flywheel, Leak-before-Break, Spent Fuel Pool Liner, Pipe Subsurface Indications, and RCP Code Case N-481 in Section 4.7 of each LRA. The staff reviewed this section of each LRA to determine whether the applicant had evaluated the TLAAs in accordance with 10 CFR 54.21(c).

4.7.1 Crane Load Cyclic Limit

The applicant described its evaluation of crane cyclic load limits in Section 4.7.1. The staff reviewed this section of each LRA to determine whether the applicant had evaluated the TLAAs in accordance with the requirements of 10 CFR 54.21(c)(1).

4.7.1.1 Summary of Technical Information in the Application

The applicant indicated that the following cranes are included in the scope of license renewal:

- containment polar cranes
- containment annulus monorails
- fuel handling bridge crane
- spent fuel crane
- auxiliary building monorails
- containment jib cranes for SPS

The applicant indicates that NUREG-0612 requires that the design of heavy load-handling systems meet the intent of Crane Manufacturers Association of America, Inc. (CMAA) Specification #70. The applicant identified the crane load cycle provided in CMAA-70 as a TLAA. The applicant indicated that the number of operating crane loads is not expected to exceed the number of design cycles and, therefore, the crane design will remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

4.7.1.2 Staff Evaluation

The applicant indicated that, based on CMAA-70, the most limiting number of loading cycles is 100,000. The applicant further indicated that the most frequently used cranes are the spent fuel cranes. The applicant estimated that the spent fuel cranes will make no more than 50,000 lifts in a 60-year period and, therefore, the number of operating load cycles will not exceed the number of cycles assumed in the design. The staff found the applicant's evaluation acceptable in accordance with the requirements of 10 CFR 54.21(c)(1).

4.7.1.3 FSAR Supplement

The applicant described its evaluation of crane cyclic load limits in Section A3.5.1 of each LRA. The applicant indicates that the number of crane operating load cycles will not exceed the number of cycles assumed in the design and, therefore, the analyses of the NAS and SPS crane design remain valid for the period of extended operation. The staff concludes the applicant's FSAR supplement summary description of the crane evaluation is adequate.

4.7.1.4 Conclusions

The staff concludes the applicant's evaluation satisfies the requirements of 10 CFR 54.21(c)(1).

4.7.2 Reactor Coolant Pump Flywheel

The applicant evaluates the TLAA relating to the reactor coolant pump flywheel in Section 4.7.2 of the LRA.

4.7.2.1 Summary of Technical Information in the Application

During normal operation, the reactor coolant pump flywheel possesses sufficient kinetic energy to potentially produce high-energy missiles in the unlikely event of failure. Conditions that may result in overspeed of the reactor coolant pump increase both the potential for failure and the increased kinetic energy. The aging effect of concern is fatigue crack initiation in the flywheel bore keyway. An evaluation of a failure over the period of extended operation was performed by the applicant. The evaluation demonstrated that the flywheel design has a high structural reliability with a very high flaw tolerance and negligible flaw crack growth over a 60-year service life.

4.7.2.2 Staff Evaluation

On July 1, 1999, the NRC staff approved the application of WCAP-14535A, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination," to the Surry reactor coolant pump (RCP) flywheels and a revision of the Surry technical specifications (TSs) to adopt a 10-year inspection interval for the flywheels. A similar application for the North Anna Units was approved on April 22, 1998. During the staff review, the applicant informed the staff that the 10-year inspection intervals for reactor coolant pump flywheels were currently in the applicant's augmented inspection program and would be carried forward to the extended period of operation. Since the analysis of WCAP-14535A is for 60 years of operation and an appropriate inspection plan is in place, the staff determined that the applicant has demonstrated the structural integrity of the RCP flywheels for the period of extended operation.

4.7.2.3 Conclusions

The staff concludes that the applicant has provided an acceptable TLAA regarding the RCP flywheel and meets 10 CFR 54.21 (c)(1)(ii).

4.7.3 Leak-Before-Break

The applicant's leak-before-break (LBB) analysis is provided in Section 4.7.3 of the LRA.

4.7.3.1 Summary of Technical Information in the Application

Westinghouse tested and analyzed crack growth with the goal of eliminating reactor coolant system primary loop pipe breaks from plant design bases. The objective of the investigation was to determine whether a postulated crack causing a leak, will grow to become unstable and lead to a full circumferential break when subjected to the worst possible combinations of plant loading.

The evaluation showed that double-ended breaks of reactor coolant pipes are not credible, and as a result, large LOCA loads on primary system components will not occur. The applicant stated that the overall conclusion of the evaluation was, that, with the worst combination of plant loading, including the effects of safe-shutdown-earthquake, the crack will not propagate around the circumference and cause a guillotine break. The plant has leakage detection systems that can identify a crack with margin, and provide adequate warning before the crack can grow.

4.7.3.2 Staff Evaluation

The applicant confirmed that the lines that had been approved by the staff for the WCAP-14535A leak-before-break (LBB) application were the primary-loop piping for both NAS 1/2 and SPS 1/2, and the bypass line for the NAS 1/2. Since the material for the North Anna bypass line is forged stainless steel, which is not subjected to thermal aging, it is not a TLAA. The previously approved Surry and North Anna LBB applications for the primary loop considered design transients and cycles for 40 years of operation. However, only the approved North Anna application considered the thermal aging effect for the cast austenitic stainless steel pipe components. To address the LBB in the context of the TLAA, the applicant performed revised LBB analyses for a 60-year plant life for the Surry and North Anna units considering the thermal aging effect for cast austenitic stainless steel pipe components, and concluded that the revised LBB analyses are valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii). The staff agrees with the applicant's conclusion for the Surry units because an appropriate analysis has been performed with acceptable results and the Surry primary-loop piping does not have welds fabricated from Alloy 82/182 weld material.

Due to the Summer main coolant loop weld cracking event involving Alloy 82/182 weld material, the staff now considers the effect of primary water stress corrosion cracking (PWSCC) on Alloy 82/182 piping welds in all LBB evaluations. For the North Anna units, only the steam generator primary-nozzles-to-safe-end welds in the primary-loop piping contain Alloy 82/182 weld material. In its response to the staff's RAI, the licensee proposed to include the following statement in Section A3.5.3 of the UFSAR Supplement: "The steam generator primary-nozzles-to-safe-end welds in the primary loop piping that have been analyzed for LBB are the only components fabricated with Alloy 82/182-weld material for NAPS 1 and 2. Dominion will continue to participate in the ongoing NRC/industry program on Alloy 82/182-weld material and will implement the findings/resolution from this effort, as appropriate." Because of this commitment and the information submitted in the draft MRP Report, "PWR Materials Reliability Program Interim Alloy 600 Safety Assessment for U.S. PWR Plants", Part 1, the staff accepts the revised LBB application for the North Anna primary-loop piping. However, the staff is continuing to review the generic implications of PWSCC on existing LBB approvals. The staff may consider the need for additional licensee action/analysis, as appropriate, to ensure that the underlying basis for the approval of LBB for the North Anna and Surry piping systems remains valid. If the staff concludes that such additional licensee action/analysis is required, this issue will constitute a generic issue, not an issue specific to the North Anna and Surry LRAs.

A detailed discussion of how the applicant is addressing the event at the V.C. Summer plant with respect to its inservice inspection program is provided in Section 3.3.1.11, "ISI Program - Component and Component Support Inspections," of this SER.

4.7.3.3 Conclusions

The staff concludes that the applicant has provided an acceptable TLAA regarding LBB and meets 10 CFR 54.21(c)(i)(ii).

4.7.4 Spent Fuel Pool Liner

4.7.4.1 Summary of Technical Information in the Application

In Section 4.7.4 of the LRA, the applicant describes the time-limited fatigue analysis related to the spent fuel pool liners for the two plants as follows:

> The spent fuel pool liner located in the Fuel Building is needed to prevent a leak to the environment. A design calculation has been identified which documents that the spent fuel pool design meets the general industry criteria. The calculation includes a fatigue analysis to add a further degree of confidence.
>
> The normal thermal cycles occur at each refueling, resulting in 80 cycles for both units in 60 years. Total number of thermal cycles is expected to be 90, which includes normal, upset, emergency, and faulted conditions.

For NAS and SPS, the calculations show that the allowable thermal cycles for spent fuel pool liner for the most severe thermal condition, which includes a loss of cooling, is 100 and 95, respectively.

Based on the above, the applicant concludes that the existing calculations remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.7.4.2 Staff Evaluation

The bulk temperature of the water in the spent fuel pool would vary depending upon the number and the age of the fuel assemblies stored in the spent fuel pool. In order to understand clearly the time-limited thermal fatigue analysis, the staff requested additional information related to the temperature ranges and number of cycles assumed in the analyses.

By letter dated January 16, 2002, the applicant responded to the staff's RAIs. The applicant provided a table describing various design conditions, expected number of cycles, and associated temperature ranges as follows:

CONDITIONS	DESCRIPTION	DESIGN CYCLES	TEMPERATURE RANGE
Condition 1 (Normal)	1/3 Core Initial Load	1	70°F - 121°F
Condition 2 (Normal)	1/3 Core Refuel with 10 years fuel in the pool	80	70°F - 135°F
Condition 3 Upset	1 core offload - 45 days after refueling abnormal condition	8	70°F - 170°F

CONDITIONS	DESCRIPTION	DESIGN CYCLES	TEMPERATURE RANGE
Condition 4 Faulted	Faulted condition	1	70°F - 212°F

The staff notes that in condition 3, the maximum temperature of the spent fuel pool concrete is likely to go above the acceptable limit of 150° F. However, considering that this is an abnormal condition, and that the spent fuel pool concrete can withstand such temperature without significantly affecting the concrete properties, the expected eight cycles in the lifetime of the plant is acceptable.

The staff also requested information related to the anchorages to the concrete walls. RAI 4.7.4-3 asks, "As the stainless steel spent fuel pool liner is attached to the concrete walls and floors, the effects of thermal cycling is on the anchorages of the liner to the concrete. Provide information that would explain how the TLAA account for these effects." The applicant's January 16, 2002 letter provided the following response:

> The NAPS pool liner was designed in accordance with the design criteria provided in the ASME Boiler and Pressure Vessel Code, Section III, Division 1 - 1974 edition; Nuclear Power Plant Components, Subsection NA (with addenda up to Summer 1976). The SPS pool liner was designed in accordance with the design criteria provided in the ASME Boiler and Pressure Vessel Code, Section III, Division 1 - 1971 edition. The following procedure was used in the existing calculations to qualify the fuel pool liner.
>
> Procedure:
>
> 1. Membrane plus bending stresses caused by differential thermal expansion was calculated using linear elastic methods of analysis.
>
> 2. If one of the following two conditions were met, the liner was considered to be acceptable.
>
>   - If stresses calculated at points, which are not welds or points of stress concentrations, the calculated stresses should be less than $3S_m$
>
>   - If stresses calculated at points, which are welds or points of stress concentrations, the calculated stresses should be less than $0.75S_m$. (Note: The limit of $0.75S_m$ results in a stress concentration factor of 4.0.)
>
> 3. If the calculated stresses exceed either $3S_m$ or $0.75S_m$ as identified in 2, then the liner is evaluated on the basis of fatigue life. The liner integrity was assessed in accordance with the cyclic loading design procedure, Paragraph XIV- 1221.3, Pages 336 and 337 of Section III. Stresses to determine the fatigue life was calculated as follows
>
>   - Stress concentration factor of 1.0 was used for points, which are not welds or points of stress concentrations.

- Stress concentration factor of 4.0 was used for points, which are welds or points of stress concentrations.

4. Appropriate design stress intensity values from Section III were used.

5. The applicable design fatigue curve from Section III was used.

For the locations with welds or stress concentrations, a factor of 4 has been used. The most limiting condition is that the concrete structure is deformed to its maximum permissible limit and is at room temperature. The liner design calculations show that the allowable cycles for the liner reaching 212°F are 100 for North Anna and 95 for Surry. This number of allowable cycles exceeds the total number of expected operating cycles (90) as identified in Section 4.7.4 of the application. Furthermore, the temperature of the fuel pool is expected to be below 135°F under normal conditions. Since the operating temperature is low, effects of sustained high temperature is not a concern.

The welding at the Surry anchorages has been analyzed for fatigue usage factor using the operating cycles listed above. It was found to be 0.578, which is less than the allowable value of 1.0. No additional analysis has been performed for North Anna, since the SPS liner is the most limiting."

Based on the procedure used for evaluating the effects of thermal fatigue cycles on the liner anchorages during the extended period of operation, the staff finds the approach reasonable and acceptable.

4.7.4.3 Conclusion

Based on the additional information provided, the staff concludes that the TLAA performed by the applicant to address the effects of thermal cycling on the spent fuel pool liners at NAS and SPS provides a reasonable assurance that the spent fuel pool liners will be able to safely withstand the thermal cyclic loads that could occur during the period of extended operation. Therefore, the TLAA is acceptable pursuant to 10 CFR 54.21(c)(1)(i).

4.7.5 Piping Subsurface Indications

Flaws in ASME Class 1 components that exceed the size of allowable flaws defined in ASME Code, Section XI, IWB-3500 need not be repaired if they are analytically evaluated to the criteria in IWB-3600 of the ASME Code. The analytic evaluation requires the licensee to project the amount of flaw growth due to fatigue and stress corrosion mechanisms, or both, where applicable, during a specified evaluation period. The applicant identified the evaluation of piping subsurface indications as a TLAA. The staff reviewed this section of both LRAs to determine whether the applicant has evaluated the TLAAs in accordance with the requirements of 10 CFR 54.21(c)(1).

4.7.5.1 Summary of Technical Information in the Application

In section 4.7.5 of both LRAs, the applicant indicated that calculations were identified at both NAS and SPS that addressed piping subsurface indications detected during inspections performed in accordance with ASME Section XI. The applicant indicated that the calculations determined the number of thermal cycles required for the flaws to reach an unacceptable size. The applicant indicated that the number of thermal cycles expected for sixty years of plant operation does not exceed the number required for these flaws to reach an unacceptable size and, therefore, the analyses remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.7.5.2 Staff Evaluation

The applicant's evaluation indicates that the number of thermal cycles required for the flaws to reach an unacceptable size exceeds the number of thermal cycles predicted for the 60-years of plant operation. Therefore, the staff concludes the analyses remain valid for the extended period of operation in accordance with 10 CFR 54.21(c)(1)(i).

4.7.5.3 FSAR Supplement

The applicant described its evaluation of subsurface indications in Section A3.5.5 of both LRAs. The applicant indicated that the number of cycles required for the flaws to reach an unacceptable size exceeds the number of cycles predicted for 60-years of plant operation. The staff concludes that the summary description of the TLAA for piping subsurface indications is adequate.

4.7.5.3 Conclusions

The staff concludes the applicant's evaluation satisfies the requirements of 10 CFR 54.21(c)(1).

4.7.6 Reactor Coolant Pump-Code Case N-481

The applicant's analysis of reactor coolant pump Code Case N-481 is given in Section 4.7.6 of the LRA.

4.7.6.1 Summary of Technical Information in the Application

Section XI of the ASME Boiler and Pressure Vessel Code require periodic volumetric inspections of the welds for the primary loop pump casings of commercial nuclear power plants. These inspections require a large amount of time and resources to complete, and result in large radiation exposure. Since the pump casings are inspected prior to being placed in service, and no significant mechanisms exist for crack initiation and propagation, it has been concluded that the inservice volumetric inspection can be replaced with an acceptable alternate inspection. In recognition of this, ASME Code Case N-481, Alternative Examination Requirements for Cast Austenitic Pump Casings, provided an alternative to the volumetric inspection requirement. The code case allows the replacement of volumetric examinations of primary loop pump casings with fracture mechanics-based integrity evaluations (Item (d) of the code case) supplemented by specific visual examinations.

The applicant stated that Westinghouse performed the primary loop piping pump casings integrity analyses to the ASME Code Case N-481 requirements. It was concluded that the primary loop pump casings are in compliance with item (d) of ASME Code Case N-481.

TLAAs related to Code Case N-481 have been identified as thermal aging of cast austenitic stainless steel (CASS) and its consequence on fatigue crack growth. Comparisons of pump casing loads with the screening loads have been made. The stability of the flaws postulated in the primary loop pump casings has been established by evaluating the necessary material properties against the saturated (fully aged) fracture toughness values. Thus, the applicant stated that Code Case N-481 is satisfied for the period of extended operation.

4.7.6.2 Staff Evaluation

Components of the RCS were designed to codes that contained explicit criteria for fatigue analysis. Consequently, the applicant identified the fatigue analyses and the flaw growth evaluations of the RCS components for compliance with the provisions of 10 CFR 54.21(c)(1).

The Code Case N-481 flaw tolerance evaluation was reviewed by the applicant to determine if the evaluation is acceptable for the period of extended operation. A separate effort was carried out to evaluate the acceptability of a Code Case N-481 flaw growth analysis for the RCS pump casings for the period of extended operation, taking into consideration the effects of thermal aging on fracture toughness. This was done by performing an integrity analyses on the primary loop piping pump casings to the ASME Code Case N-481 requirements. The primary loop pump casings were found to be in compliance with Item (d) of ASME Code Case N-481. Code Case N-481 was approved by the staff in regulatory guide 1.147, revision 5. Therefore, the staff agrees that the flaw growth evaluation for pump casings is acceptable for the period of extended operation.

4.7.6.3 Conclusions

The staff concludes that the applicant has provided an acceptable TLAA regarding the use of NRC -approved Code Case N-481 and meets 10 CFR 54.21(c)(1)(ii).

5.0 Review by the Advisory Committee on Reactor Safeguards (ACRS)

The NRC staff issued its SER with open items related to the license renewal of the North Anna power station Units 1 and 2, and Surry power station Units 1 and 2 on June 6, 2002. On July 9, 2002, the NRC staff briefed the Advisory Committee on Reactor Safeguards (ACRS) subcommittee on plant license renewal on the SER with open items. Due to the small number of open items, the ACRS subcommittee did not issue an interim letter on its review of the SER with open items. The staff finalized and issued its SER related to the license renewal of the North Anna power station Units 1 and 2, and Surry power Units 1 and 2 on November 5, 2002.

During its 498th meeting on December 5-7, 2002, the ACRS full committee completed its review of the Dominion's license renewal applications and the NRC staff's safety evaluation report. The ACRS documented its findings in a letter to the Commission dated December 18, 2002. A copy of the ACRS full committee is attached.

December 18, 2002

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

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATIONS FOR THE NORTH ANNA POWER STATION UNITS 1 AND 2 AND THE SURRY POWER STATION UNITS 1 AND 2

Dear Chairman Meserve:

During the 498th meeting of the Advisory Committee on Reactor Safeguards, December 5-7, 2002, we completed our review of the License Renewal Application for North Anna Power Station (NAS) Units 1 and 2, the Surry Power Station (SPS) Units 1 and 2, and the final Safety Evaluation Report (SER) prepared by the staff of the U. S. Nuclear Regulatory Commission (NRC). Our review included a meeting of our Plant License Renewal Subcommittee on July 9, 2002. During our review, we had the benefit of discussions with representatives of the NRC staff and Virginia Electric and Power Company (Dominion). We also had the benefit of the documents referenced.

CONCLUSIONS AND RECOMMENDATIONS

1. The Dominion application for renewal of the operating licenses for NAS Units 1 and 2 and SPS Units 1 and 2 should be approved.

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

BACKGROUND AND DISCUSSION

This report fulfills the requirement of 10 CFR 54.25 which states that the ACRS should review and report on license renewal applications. Dominion requested renewal of the operating licenses for NAS Units 1 and 2 and SPS Units 1 and 2 for a period of 20 years beyond the current license terms, which expire on April 1, 2018 (NAS Unit 1); August 21, 2020 (NAS Unit 2); May 25, 2012 (SPS Unit 1); and January 29, 2013 (SPS Unit 2). The final SER, issued on November 5, 2002, documents the results of the staff's review of information submitted by Dominion, including commitments that were necessary to resolve the open items identified by the staff in the initial SER. This review of the application was conducted concurrently for two stations with a total of four units. Given the similarity of the units and the formatting of the application, which clearly highlighted the few differences, the concurrent review did not present any unusual difficulties.

The staff reviewed the completeness of the identification of structures, systems, and components (SSCs) subject to aging management; the integrated plant assessment process; the applicant's identification of the possible aging mechanisms associated with passive, long-lived components; and the adequacy of the aging management programs. The staff also conducted three inspections. First, a 1-week inspection was performed to assess the applicant's scoping and screening methodology. Next a 1-week inspection was conducted at each facility to assess plant material condition and aging management programs. Lastly, an inspection was performed to close open items resulting from the earlier inspections.

The staff provided the Committee with details of the scope and results of its inspections of material condition at both plants. We agree with the staff's assessment that there are no issues that would preclude renewal of the operating license for NAS Units 1 and 2 and SPS Units 1 and 2.

On the basis of our review of the final SER, we agree that all open items and confirmatory items have been appropriately closed. We also discussed several items that were raised at the Subcommittee meeting on July 9, 2002, and found that the staff and the applicant have satisfactorily addressed each item.

The processes implemented by the applicant to identify SSCs that are within the scope of license renewal were effective. As with several previous applicants, the staff engaged in considerable discussion with the applicant regarding the portion of the offsite power system to be included within the scope of license renewal. After reviewing the information provided by the applicant, we agree that appropriate portions of the offsite power system are included in scope. During our review, we questioned why certain other SSCs were not included within the scope and, in all cases, the applicant provided appropriate justification for exclusion.

The applicant has performed a comprehensive aging management review of SSCs that are within the scope of license renewal. There are 19 existing aging management programs and four new programs.

The applicant has satisfactorily responded to NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," dated March 18, 2002. Further, the applicant has committed to replace all four reactor vessel heads. The replacement of the NAS Unit 2 head is currently in progress.

The applicant used the guidance specified in Westinghouse Owners Group reports for reactor coolant system piping, pressurizer, and reactor internals. The staff reviewed and approved the use of these reports with certain stipulations. Each stipulation was sufficiently addressed in the staff's review.

We questioned the method by which reactor coolant piping is to be inspected in light of the failure of the initial volumetric inservice inspection to detect vessel nozzle cracking at V.C. Summer. Although continued improvement in the inspection methodology is warranted, the staff considers current methods adequate to detect primary water stress corrosion cracking. This is a generic issue and we remain concerned with the effectiveness of inspection techniques. Dominion has committed to employ best industry practices as they are developed.

Dominion has also committed to conduct a one-time inspection of a representative sample of buried piping. Opportunistic inspections of in-scope buried piping will be performed when the piping is uncovered during other maintenance activities. If significant degradation is identified, the results will be entered into the licensee's corrective action program and the inspection will be expanded. If no opportunity presents itself by the end of the current license period, excavations will be made to inspect the piping.

The applicant's erosion/corrosion program is of particular interest in light of the previous carbon steel piping failures at SPS. Dominion uses the CHECWORKS program to identify locations to be monitored and trend erosion/corrosion rates. The program appears to be effective in managing erosion/corrosion.

Certain medium-voltage cables exposed to moisture for long periods of time fail due to a phenomenon called "water treeing." To preclude this failure, the applicant has committed to a program that will control water in manholes and underground ducts associated with energized power cables. The Cable Monitoring Activities Program for non-environmentally qualified cable has been enhanced to ensure that if degraded cable is identified, the cable environment, including the potential for moisture shall be evaluated and appropriate corrective actions initiated through the corrective action program.

During the discussion of time-limited aging analyses, we expressed a concern that the applicant had not submitted its evaluations of the reactor vessel margins for pressurized thermal shock and upper shelf energy. The staff had accepted the applicant's position that these values were acceptable without performing an independent evaluation. Subsequently, the staff obtained this information from the applicant and the staff performed an independent evaluation. Although in some cases the margins are small, we agree with the staff's position that margin does exist. We believe that in the future such critical parameters should be reviewed by the staff. The staff agreed to require that these data be provided with future license renewal applications.

In several situations, Dominion and other applicants have committed to actions based on future technology development. In Dominion's case, two examples are (1) the method for inspecting reactor coolant piping, and (2) the method for testing of medium-voltage cables exposed to moisture. The NRC staff needs to continue to keep abreast of these developing technologies and review and approve methodologies at the appropriate time.

License renewal applications include a number of activities and commitments, for example one-time inspections, that will not be accomplished until near the end of the current license period. There is a large amount of inspection activity that needs to be conducted at that time period. The staff is aware of this future work load and is working on a plan to properly manage this significant effort.

The applicant and the staff have identified plausible aging effects associated with passive, long lived components. Adequate programs have been established to manage the effects of aging so that NAS Units 1 and 2 and SPS Units 1 and 2 can be operated in accordance with their current licensing bases for the period of extended operation without undue risk to the health and safety of the public.

Sincerely,

/RA/

George E. Apostolakis
Chairman

<u>References:</u>

- U.S. Nuclear Regulatory Commission, "Safety Evaluation Report Related to the License Renewal of the North Anna Power Station, Units 1 and 2, and the Surry Nuclear Station, Units 1 and 2," issued November 2002.
- Dominion Application for Renewed Operating License for North Anna Power Station, Units, 1 and 2, and Surry Power Station, Units 1 and 2, submitted May 29, 2001.

6.0 Conclusions

The NRC staff reviewed Dominion's license renewal applications for North Anna, Units 1 and 2 and Surry, Units 1 and 2, in accordance with Commission's regulations and the NRC's draft Standard Review Plan (SRP) for the Review of License Renewal Applications for Nuclear Power Plants," dated August 2000. The SRP was revised and issued as NUREG-1800 in July 2001. The standards for renewing an operating license are set forth in 10 CFR 54.29.

On the basis of its review of the applications and evaluation, the staff has determined that the requirements of 10 CFR 54.29(a) have been met.

The NRC staff notes that the requirements of Subpart A of 10 CFR Part 51 are documented in NUREG-1437, Supplements 6 and 7, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regrading Surry Power Station, Units 1 and 2" and "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regrading North Anna Power Station, Units 1 and 2," dated November 2002.

Appendix A: Chronology

This appendix contains a chronological listing of routine licensing correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff and Virginia Electric and Power Company (Dominion). This appendix also contains other correspondence regarding the NRC staff's review of the North Anna power station, Units 1 and 2, (under docket Nos. 50-338, 50-339), and Surry power station, Units 1 and 2 (under docket Nos. 50-280, and 50-281.)

May 29, 2001	In a letter (signed by D. Christian) Dominion submitted its applications to renew the operating licenses of North Anna and Surry power stations. In its submittal, Dominion provided one hard copy of the applications and 37 copies of applications on CDs. (ADAMS Accession Number: ML011500496)
May 29, 2001	In a letter (signed by D. Christian) Dominion submitted five sets of boundary drawings to the NRC. (ADAMS Accession Number: ML011500498)
July 3, 2001	In a letter (signed by D. Matthews) NRC informed Dominion that the NRC had received its applications to renew the operating licenses of North Anna and Surry power stations on May 29, 2001, and that Mr. Robert Prato was appointed as the project manager for the North Anna and Surry LRAs. (ADAMS Accession Number: ML011900065)
July 18, 2001	In a letter (signed by R. Prato) NRC issued a summary for the public meeting held on June 27, 2001. In this meeting, Dominion made a presentation to the NRC staff and members of the public regarding information contained In the North Anna and Surry LRAs. (ADAMS Accession Number: ML012000293)
July 23, 2001	In a letter (signed by C. Grimes) NRC published an "acceptance for docketing and opportunity for hearing" Federal Register Notice (FRN) as to North Anna and Surry LRAs. (ADAMS Accession Number: ML
July 30, 2001	In a letter (signed by D. Matthews) NRC informed Dominion that the NRC staff determined that the information contained In the North Anna and Surry LRAs submitted in May 29, 2001, was acceptable for docketing, and sufficient for the staff to begin its review. (ADAMS Accession Number: ML012120025)
August 8, 2001	In a letter (signed by R. Prato) the summary of a telecommunication between the staff and Dominion representatives was published and documented. The telecommunication was held on July 31, 2001, to clarify

	information provided by Dominion in its LRAs Sections 2.5, 3.3.1, 3.3.6, and B2.1.1. (ADAMS Accession Number: ML012260187)
August 8, 2001	In a letter (signed by R. Prato) the NRC staff requested for additional information (RAIs) regarding Sections 2.5 and B2.1.1 of North Anna and Surry LRAs. (ADAMS Accession Number: ML012260171)
October 11, 2001	In a letter (signed by R. Prato) the NRC staff requested for additional information (RAIs) regarding Sections 3.1.1, 3.1.2, 3.5.1, 3.5.2, 3.5.3, 3.5.4, 4.4, B2.2.1, B2.2.7, B2.2.9, B2.2.17, and B2.2.19 of North Anna and Surry LRAs. (ADAMS Accession Number: ML012860003)
October 11, 2001	In a letter (signed by R. Prato) the summary of five telecommunications between the staff and Dominion representatives was published and documented. These telecommunications were held on August 8, 9, 13, 27, and 28, 2001, to clarify information provided by Dominion in its North Anna and Surry LRAs, Sections 2.3.3.7, 2.3.3.16, 3.1.1.2, 3.1.2.2, 3.1.3.2, 3.1.4.2, 3.2.2, 3.3.9, 3.5, B2.1.2, B2.2.1, B2.2.4, B2.2.5, B2.2.7, B2.2.9, B2.2.17, and B2.2.19. (ADAMS Accession Number: ML012840320)
October 22, 2001	In a letter (signed by R. Prato) the NRC staff requested for additional information (RAIs) regarding Sections 2.1, B2.0, 4.1, 4.3, and 4.7.4 of North Anna and Surry LRAs. (ADAMS Accession Number: ML013040121)
October 22, 2001	In a letter (signed by R. Prato) the NRC staff requested for additional information (RAIs) regarding Sections 3.6, 4.7.3, and B2.1.3 of North Anna and Surry LRAs. (ADAMS Accession Number: ML013040164)
October 25, 2001	In a letter (signed by R. Prato) the summary of two telecommunications between the staff and Dominion representatives was published and documented. These telecommunications were held on September 25 and 26, 2001, to clarify information provided by Dominion in its North Anna and Surry LRAs, Sections 2.4.1, 2.4.2, 2.4.3, 2.4.4, 2.4.5, 2.4.6, 2.4.7, 2.4.9, 4.1, 4.3, and 4.7.4. (ADAMS Accession Number: ML012990334)
October 25, 2001	In a letter (signed by R. Prato) the summary of two telecommunications between the staff and Dominion representatives was published and documented. These telecommunications were held on October 3 and 4, 2001, to clarify information provided by Dominion in its North Anna and

	Surry LRAs, Sections 2.2, 2.3.3.29, 2.3.3.31, 2.3.3.34, 3.6, 4.7.2, 4.7.3, B2.1.3, and B2.2.2. (ADAMS Accession Number: ML013020127)
November 14, 2001	In a letter (signed by R. Prato) the NRC staff requested for additional information (RAIs) regarding Sections 2.3.1 and 2.3.2 of North Anna and Surry LRAs. (ADAMS Accession Number: ML013180452)
November 14, 2001	In a letter (signed by R. Prato) the summary of three telecommunications between the staff and Dominion representatives was published and documented. These telecommunications were held on October 9, 11, and 15, 2001, to clarify information provided by Dominion in its North Anna and Surry LRAs, Sections 2.3.1, 2.3.1.3, 2.3.1.4, 2.3.1.5, 2.3.2.4, 2.3.3.1, 2.3.3.3, 2.3.3.4, 2.3.3.9, 2.3.3.30, 3.1.5.2.1, 3.1.5.2.2, 4.2.1, 4.2.2, B2.2.8, and B2.2.18. (ADAMS Accession Number: ML013190418)
November 26, 2001	In a letter (signed by R. Prato) the NRC staff requested for additional information (RAIs) regarding Sections 2.3.3.21, 2.3.3.31, 2.3.4, and 3.5 of North Anna and Surry LRAs. (ADAMS Accession Number: ML013300471)
November 30, 2001	In a letter (signed by D. Christian) Dominion submitted its response to the NRC staff's request for additional information (RAIs) dated October 11, 2001, regarding Sections 3.1.1, 3.5.1, 3.5.2, 3.5.3, 3.5.4, 3.6.2, 4.4, B2.2.1, B2.2.7, B2.2.9, B2.2.17, and B2.2.19 of North Anna and Surry LRAs. (ADAMS Accession Number: ML020030330)
December 5, 2001	In a letter (signed by R. Prato) the summary of three telecommunications between the staff and Dominion representatives was published and documented. These telecommunications were held on November 14, 19, and 21, 2001, to clarify information provided by Dominion in its North Anna and Surry LRAs, Sections 2.3.3.10, 2.3.3.11, 2.3.3.21, 2.3.3.31, 2.3.4.1, 2.3.4.2, 2.3.4.3, 2.3.4.4, 2.3.4.5, 2.3.4.6, 2.3.4.7, 2.4.8, 2.4.10, 2.4.12, 3.5.5, 3.5.6, 3.5.8, 3.5.9, 3.5.10, 3.5.11, B2.2.6, B2.2.10, B2.2.11, and B2.2.12. (ADAMS Accession Number: ML013400189)
January 4, 2002	In a letter (signed by D. Christian) Dominion submitted its response to the NRC staff's request for additional information (RAIs) dated October 22, 2001, regarding Sections 3.6, 4.7.3, and B2.1.3 of North Anna and Surry LRAs. (ADAMS Accession Number: ML020160075)

January 4, 2002	In a letter (signed by D. Christian) Dominion submitted its response to the NRC staff's request for additional information (RAIs) dated November 14, 2001, regarding Sections 2.3.1 and 2.3.2 of North Anna and Surry LRAs. (ADAMS Accession Number: ML020160066)
January 16, 2002	In a letter (signed by D. Christian) Dominion submitted its response to the NRC staff's request for additional information (RAIs) dated October 22, 2001, regarding Sections 4.1, 4.3, 4.7.4, and B2.0 of North Anna and Surry LRAs. (ADAMS Accession Number: ML020230330)
January 17, 2002	In a letter (signed by R. Prato) the NRC published a public meeting summary which was held on December 12, 2001, between the NRC, Nuclear Energy Institute (NEI), Dominion, and Duke Energy Corporation regarding license renewal emerging issues. (ADAMS Accession Number: ML020300026)
January 22, 2002	In a letter (signed by R. Prato) the NRC published a public meeting summary which was held on January 10, 2002, between the NRC and Dominion regarding the treatment of station blackout issue In the North Anna and Surry LRAs. (ADAMS Accession Number: ML020220368)
January 30, 2002	In a letter (signed by R. Prato) the summary of two telecommunications between the staff and Dominion representatives was published and documented. These telecommunications were held on January 28 and 29, 2002, to clarify information provided by Dominion in its North Anna and Surry LRAs, Sections 4.4, and B2.2.3. (ADAMS Accession Number: ML020350508)
February 1, 2002	In a letter (signed by D. Christian) Dominion submitted its response to the NRC staff's request for additional information (RAI) dated October 22, 2001, regarding Section 3.6 of North Anna and Surry LRAs. (ADAMS Accession Number: ML021970004)
February 1, 2002	In a letter (signed by D. Christian) Dominion submitted its response to the NRC staff's request for additional information (RAI) dated October 22, 2001, regarding Section 2.1 of North Anna and Surry LRAs. (ADAMS Accession Number: ML021970005)
February 5, 2002	In a letter (signed by D. Christian) Dominion submitted its response to the NRC staff's requests for additional information (RAIs) dated November 26, 2001, regarding Sections 2.3.3.21, 2.3.3.31, 2.3.4, 3.5, B2.2.6, B2.2.10, B2.2.11, and B2.2.12, of

	North Anna and Surry LRAs. (ADAMS Accession Number: ML021970007)
April 22, 2002	In an electronic mail (sent by M. Henig to O. Tabatabai) Dominion transmitted supplemental response to the staff's RAI 4.3-6. (ADAMS Accession Number: ML021410080)
April 29, 2002	In an electronic mail (sent by M. Henig to O. Tabatabai) Dominion transmitted a supplemental response to the NRC staff's request for additional information (RAI) 2.5-1, and compliance with staff's position on SBO. (ADAMS Accession Number: ML021330417)
May 22, 2002	In a letter (signed by D. Christian) Dominion submitted its formal concurrence on contents of the telecommunication summaries prepared by R. Prato on August 8, 2001, October 11, 2001, and January 30, 2002. (ADAMS Accession Number: ML021510279)
May 22, 2002	In a letter (signed by D. Christian) Dominion submitted its supplemental responses to the NRC staff's RAIs 2.1-3, 3.5-5, 3.5.8-2, 3.5.9-2, 3.5.9-4, 3.5.9-5, B2.2.7-1, B2.2.7-2, B2.2.7-3, B2.2.11-1, and B2.2.19-3 regrading the North Anna and Surry LRAs. (ADAMS Accession Number: ML021480185)
June 6, 2002	In a letter (signed by P.T. Kuo) the NRC staff issued its draft safety evaluation report with open items related to the license renewal of North Anna and Surry nuclear stations. (ADAMS Accession Number: ML021580123)
June 19, 2002	In an electronic mail (sent by M. Henig to O. Tabatabai) Dominion submitted its revised SBO and Non-EQ Cables Aging Management Activity Letter, Serial No. 02-297, to the NRC. (ADAMS Accession Number: ML021890549)
July 5, 2002	In an electronic mail (sent by T. Snow to O. Tabatabai) Dominion submitted its Technical Report LR-1921/LR-2921, Criterion 2 Evaluation, to the NRC. (ADAMS Accession Number: ML021890423)
July 16, 2002	In an electronic mail (sent by M. Henig to O. Tabatabai) Dominion transmitted its editorial comments on the draft safety evaluation report related to the license renewal applications for North Anna and Surry. (ADAMS Accession Number: ML021990430)
July 31, 2002	In an electronic mail (sent by M. Henig to O. Tabatabai) Dominion transmitted additional information on staff's RAI 2.1-3. (ADAMS Accession Number: ML022170561)

August 01, 2002	In an electronic mail (sent by M. Henig to O. Tabatabai) Dominion transmitted data on reactor vessel beltline neutron fluence, pressurized thermal shock, and Charpy upper shelf energy for North Anna and Surry reactor vessels. (ADAMS Accession Number: ML022190253)
August 20, 2002	In an electronic mail (sent by T. Snow to O. Tabatabai) Dominion provided additional information related to the dissimilar metal weld cracking event in V. C. Summer. (ADAMS Accession Number: ML022390432)
August 22, 2002	In an electronic mail (sent by M. Henig to O. Tabatabai) Dominion transmitted three topical reports; BAW-2178P, BAW-2192P, and BAW-2323. (ADAMS Accession Number: ML022390113)
August 23, 2002	In a letter (signed by L. Hartz) Dominion submitted a supplemental response to the staff's RAI 2.1-3. (ADAMS Accession Number: ML022460156)
August 23, 2002	In an electronic mail (sent by M. Henig to O. Tabatabai) Dominion transmitted additional information on evaluation of Surry 1/2 reactor vessel material surveillance data. (ADAMS Accession Number: ML022400102)
August 29, 2002	In a letter (signed by O. Tabatabai) the NRC staff published the summary of a meeting with Dominion representatives on August 08, 2002. The purpose of this meeting was to discuss comments provided by the Advisory Committee on Reactor Safeguards (ACRS) on the staff's draft safety evaluation report. (ADAMS Accession Number: ML022410357)
September 10, 2002	In a letter (signed by O. Tabatabai) the NRC staff published the summary of two telecommunications between the staff and Dominion representatives. These telecommunications were held on August 20 and 22, 2002, to clarify information provided by Dominion on reactor vessel neutron embrittlement evaluations (ADAMS Accession Number: ML022530347)
September 10, 2002	In an electronic mail (sent by M. Henig to O. Tabatabai) Dominion transmitted a revised response to the staff's RAI 4.3-6. (ADAMS Accession Number: ML022730096)
September 18, 2002	In a letter (signed by O. Tabatabai) the NRC staff informed Dominion that the third inspection of the North Anna and Surry Nuclear Stations was rescheduled for September 27, 2002. (ADAMS Accession Number: ML022620260)

September 18, 2002	In an electronic mail (sent by M. Henig to O. Tabatabai) Dominion transmitted a draft report on Surry 1/2 reactor vessel beltline neutron fluence, PTS, and USE data on reactor vessel beltline neutron fluence, pressurized thermal shock, and Charpy upper shelf energy. (ADAMS Accession Number: ML022620688)
September 26, 2002	In a letter (signed by O. Tabatabai) the NRC staff published the summary of two telecommunications between the staff and Dominion representatives. These telecommunications were held on September 4 and 19, 2002, regarding Dominion's report on reactor vessel surveillance data. (ADAMS Accession Number: ML022700123)
October 1, 2002	In a letter (signed by L. Hartz) Dominion submitted a supplemental response to the staff's Open Item 4.3-6. (ADAMS Accession Number: ML022810329)
October 15, 2002	In a letter (signed by L. Hartz) Dominion formally submitted all the information that were provided to the staff and/or discussed during telecommunications held on August 20 and 22, September 4 and 19, and October 9, 2002, regarding Surry 1 and 2, and North Anna 1 and 2 reactor vessel neutron embrittlement TLAA. (ADAMS Accession Number: ML022960411)
October 21, 2002	In a letter (signed by O. Tabatabai) the NRC published the summary of a telecommunication between the staff and Dominion representatives on October 9, 2002, to receive additional information from Dominion on reactor vessel neutron embrittlement evaluations. (ADAMS Accession Number: ML022940533)
October 21, 2002	In a letter (signed by O. Tabatabai) the NRC staff provided Dominion with the revised 22-month review schedule for the license renewal of the North Anna and Surry nuclear stations. (ADAMS Accession Number: ML022950104)
November 4, 2002	In a letter (signed by L. Hartz) Dominion committed to implement, at North Anna and Surry, the final staff guidance on the aging management of fuse holders. (ADAMS Accession Number: ML023080355)
November 5, 2002	In a letter (signed by P.T. Kuo) the NRC staff issued its Safety Evaluation Report Related to the License Renewal of the North Anna Power Station Units 1 and 2, and Surry Power Station Units 1 and 2," (ADAMS Accession Number: ML023090552)

December 2, 2002	In a letter (signed by E. Grecheck) Dominion committed to expand the scope of the Civil Engineering Structural Inspection program to consider the potential for seasonal chemistry variation in annual groundwater monitoring at North Anna and Surry. (ADAMS Accession Number: ML023400532)

Appendix B: References

This appendix contains a listing of references used in preparation of this safety evaluation report during review of NAS 1/2 and SPS 1/2 LRAs.

American Concrete Institute (ACI)

ACI-349.3R, *Evaluation of Nuclear Safety-Related Concrete Structures*, American Concrete
Institute, Farmington Hills, Michigan.

American National Standards Institute (ANSI)

ANSI B30.2-1976, *Overhead and Gantry Cranes.*

ANSI B30.11-1973, *Monorail Systems and Underhung Cranes.*

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ANSI B30.2-1976, *Overhead and Gantry Cranes*

ANSI B31.1, *Power Piping Code*

American Society of Mechanical Engineers (ASME)

Code Case N-577, *Risk-informed Requirements for Class 1, 2, and 3 Piping*, ASME Section
XI, American Society of Mechanical Engineers, New York.

Code Case N-481, Alternate Examination Requirements for Cast Austenitic Pump Casings,
ASME Section XI, American Society of Mechanical Engineers, New York.

Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Vessel Pressure Code, American Society of Mechanical Engineers, July 1986.

Section III, *Rules for Construction of Nuclear Vessels*, ASME Boiler and Vessel Pressure
Code, American Society of Mechanical Engineers, 1971.

American Society for Testing Materials (ASTM)

ASTM-E185, *Standard Practice for Conducting Surveillance Tests for Light-Water Cooled
Nuclear Power Reactor Vessels.*

Eclectic Power Research Institute (EPRI)

TR-107514, *Aging-Related Degradation Inspection Methodology and Demonstration*

TR-103842, *Class 1 Structures License Renewal Industry Report*, Revision 1,
TR-107569, *Power Steam Generator Examination Guidelines,*

NSAC-202L, *Recommendation for an Effective Flow-accelerated Corrosion Program,*

TR-105714, *PWR Primary Water Chemistry Guidelines,*

TR-102134, *PWR Secondary Water Chemistry Guidelines*

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SAND 96-0344, UC-523, *Aging Management Guideline for Commercial Nuclear Power Plants-Electrical Cable and Terminations*

TR-107515, *Evaluation of Thermal Fatigue Effects on Systems Requiring Aging Management Review for License Renewal for Calvert Cliffs Nuclear Power Plant*

TR-105759, *An Environmental Factor Approach to Account for Reactor Water Effects in Light Water Reactor Pressure Vessel and Piping Fatigue Evaluations*

TR-110043, *Evaluation of Environmental Fatigue Effects for a Westinghouse Nuclear Power Plant*

TR-110356, *Evaluation of Environmental Thermal Fatigue Effects on Selected Components in a Boiling Water Reactor Plant*

TR-107943, *Environmental Fatigue Evaluations of Representative BWR Components*

Nuclear Energy Institute (NEI)

NEI 97-06, *Steam Generator Program Guidelines*, Revision 1, Nuclear Energy Institute.

NEI 95-10, *Industry Guidance for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule*, Revision 2, August 2000.

U.S. Nuclear Regulatory Commission (NRC)

Bulletins (BL)

IE Bulletin 79-01B, *Environmental Qualification of Class 1E Equipment*, Office of Inspection and Enforcement, January 14, 1980 (Supplement 1 dated 2/29/80; Supplement 2 dated 9/30/80; and Supplement 3 dated 10/24/80).

IE Bulletin 88-09, *Thimble Tube Thinning in Westinghouse Reactors*, Nuclear Regulatory Commission, Office of Inspection and Enforcement, July 26, 1988.

Information Bulletin 82-02, *Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants*, U.S. Nuclear Regulatory Commission, June 2, 1982.

Information Bulletin 2001-01, *Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles*, U.S. Nuclear Regulatory Commission, August 30, 2001.

Information Bulletin 2002-01, *Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity*, U.S. Nuclear Regulatory Commission, March 18, 2002.

Information Bulletin 2002-02, *Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs*, U.S. Nuclear Regulatory Commission, August 9, 2002.

Code of Federal Regulations

10 CFR 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*, U.S. Nuclear Regulatory Commission.

10 CFR 51, *Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions*, U.S. Nuclear Regulatory Commission.

10 CFR 72, *Licensing Requirements for the Independent Storage of Spent Nuclear Fuel and High-level Radioactive Waste*, U.S. Nuclear Regulatory Commission.

Generic Letters (GL)

Generic Letter 88-05, *Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants*, March 17, 1988.

Generic Letter 89-08, *Erosion/Corrosion-Induced Pipe Wall Thinning*, May 2, 1989.

Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Equipment*, July 18, 1989 (Supplement 1 dated 4/4/90).

Generic Letter 97-01, *Degradation of Control Rod Drive Mechanism Nozzle and Other*

Vessel Closure Head Penetrations, Nuclear Regulatory Commission, April 1, 1997.

Generic Letter 91-17, *Generic Safety Issue 29, "Bolting Degradation or Failure in Nuclear Power Plants"*, U.S. Nuclear Regulatory Commission, October 17, 1991.

Information Notices (IN)

IN 94-58, *Reactor Coolant Pump Lube Oil Fire*, Information Notice, Nuclear Regulatory Commission, Washington, D.C.

IN 2000-17, *Crack in Weld Area of Reactor Coolant System Hot Leg Piping at* V. C. Summer, Information Notice, Nuclear Regulatory Commission, Washington, D.C.

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Letter from C. I. Grimes, U. S. Nuclear Regulatory Commission, to D. J. Walters, Nuclear Energy Institute, License Renewal Issue No. 98-0030, *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components*, May 19, 2000.

Letter from C. I. Grimes, U. S. Nuclear Regulatory Commission, to D. J. Walters, Nuclear Energy Institute, License Renewal Issue No. 98-012, *Consumables*, April 20, 1999

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Letter from C. I. Grimes, U. S. Nuclear Regulatory Commission, to D. J. Walters, Nuclear Energy Institute, Request for Additional Information Regarding Generic License Renewal Issue No. 98-0102, *Screening of Equipment that is Kept in Storage,* February 11, 1999

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Commission, *Closeout of Generic Safety Issue 190,* December 26, 1999.

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NUREG/CR-6583, *Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels,* U.S. Nuclear Regulatory Commission, March 1998.

NUREG/CR-5704, *Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels,* U.S. Nuclear Regulatory Commission, April 1999.

NUREG-0612, *Control of Heavy Loads at Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, July 1980.

NUREG-1344, *Erosion/Corrosion-Induced Pipe Wall Thinning in US Nuclear Power Plants,* April 1, 1989.

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NUREG-0933, *A Prioritization of Generic Safety Issues,* U.S. Nuclear Regulatory Commission, June 2000.

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NUREG/CR-6583, *Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels,* U.S. Nuclear Regulatory Commission, March 1998.

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GSI190, *Fatigue Evaluation for Metal Components for 60-year Plant Life*, U.S. Nuclear Regulatory Commission, August 1996.

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DG 1053, *Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence*, June 1996.

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Commission, *Surry Power Station Units 1 and 2, and North Anna Power Station Units 1 and 2,*

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Appendix D: Commitments Listing

During the review of Dominion LRAs by the NRC staff, the applicant made commitments to provide aging management programs to manage aging effects on structures and components prior to the expiration of its current operating license terms. The following table lists these commitments along with their implementation schedule.

Item	Commitment	UFSAR Supplement Location	Implementation Schedule	Source
1	Develop and implement an inspection program for buried piping and valves.	18.1.1	One-Time between years 30-40. Additional inspections based on results.	LRA (App. A, & Table B4.0), RAI B2.1.1-1
2	Add PZR surge line to Augmented Inspection Program.	18.2.1	Prior to PEO	LRA Table B4.0, RAI 4.3-7
3	Add core barrel hold-down spring to Augmented Inspection Program.	18.2.1	Prior to PEO	LRA Table B4.0
4	Expand scope of Civil Eng Structural Inspection to cover LR requirements.	18.2.6	Prior to PEO	LRA Table B4.0
5	Revise plant documents to use inspection opportunities when inaccessible areas become accessible during work activities.	18.2.6	Prior to PEO	LRA Table B4.0
6	Incorporate NFPA-25, Section 2-3.1.1 for sprinklers.	18.2.7	Prior to year 50. If testing used, repeat every 10 years.	LRA Table B4.0
7	Develop inspection criteria for non-ASME supports and doors.	18.2.9	Prior to PEO	LRA Table B4.0

PEO: Period of Extended Operation

Item	Commitment	UFSAR Supplement Location	Implementation Schedule	Source
8	Develop procedural guidance for inspection criteria that puts focus on aging effects.	18.2.9	Prior to PEO	LRA Table B4.0
9	Develop and implement inspection program for infrequently accessed areas.	18.1.2	One-Time between years 30-40. Additional inspections based on results.	LRA (App. A, & Table B4.0), RAI 3.5-1, RAI 3.5.8-1
10	Develop and implement inspection program for tanks.	18.1.3	One-Time between years 30-40. Additional inspections based on results.	LRA (App. A, & Table B4.0)
11	Follow industry activities related to failure mechanisms for small-bore piping. Evaluate changes to inspection activities based on industry recommendations.	18.2.11	On-going activity	LRA Table B4.0, RAI 3.1.1.2-2
12	Follow industry activities related to core support lugs. Evaluate need to enhance inspection activities based on industry recommendations.	18.2.13	On-going activity	LRA Table B4.0
13	Inspect representative sections of polar crane box girders.	18.2.10	One-Time between years 30-40. Additional inspections based on results.	LRA Table B4.0
14	Follow industry activities related to RV internals issues such as void swelling, thermal and neutron embrittlement, etc. Evaluate industry recommendations. Inspect accordingly.	18.2.15	One-Time inspection between years 30-40 on most susceptible single unit (SPS or NAPS). Additional inspections based on results.	LRA Table B4.0

PEO: Period of Extended Operation

Item	Commitment	UFSAR Supplement Location	Implementation Schedule	Source
15	Implement changes into procedures to assure consistent inspection of components for aging effects during work activities.	18.2.19	Prior to PEO	LRA Table B4.0
16	Incorporate groundwater monitoring into the civil engineering structural monitoring program. Consider groundwater chemistry in engineering evaluations of deficiencies	18.2.6	Prior to PEO	RAI 3.5-2
17	Incorporate management of concrete aging into the civil structural monitoring program and the infrequently accessed area inspection programs.	18.1.3 and 18.2.6	Prior to PEO	RAI 3.5-7
18	Incorporate management of elastomers into the work control activities.	18.2.19	Prior to PEO	RAI 3.5.6-4, RAI B2.2.19-3
19	Develop and implement inspection program for Non-EQ cables.	18.1.4	One-Time between years 30-40. Additional inspections every 10 years thereafter.	RAI 3.6.2-1
20	Follow industry activities related to Alloy 82/182 weld material. Implement activities based on industry recommendations, as appropriate.	18.3.5.3	On-going activity	RAI 4.7.3-1
21	Inspectors credited in the Work Control Process will be QMR or VT qualified.	18.2.19	Prior to PEO	RAI B2.2.19-1

PEO: Period of Extended Operation

Item	Commitment	UFSAR Supplement Location	Implementation Schedule	Source
22	Perform audit of work control inspections to ensure representation by all in-scope LR systems and to determine need for supplemental inspections.	18.2.19	Prior to PEO and every 10 years thereafter. Supplemental inspections within 5 year of audit.	RAI B2.2.19-3
23	Measure the sludge buildup in the SW reservoir at NAPS.	18.2.17	One-Time between years 35 and 40	RAI 3.5.8-2
24	Provide inspection details for PZR surge line inspections to the NRC for review and approval	18.3.2.4	Prior to PEO	RAI 4.3-7, RAI 4.3-6
25	Provide inspection details for SI and charging line inspections to the NRC for review and approval.	18.3.2.4	Prior to PEO	RAI 4.3-6, SER OI 4.3-1
26	Address NRC staff final guidance regarding fuse holders when issued.	18.1.4	When issued or prior to PEO, whichever is later.	Ltr. No. 02-691
27	Develop and implement a program to control water intrusion into manholes at SPS.	18.1.4	Prior to PEO	RAI 3.6.2-1
28	Revise procedures for groundwater testing to account for possible seasonal variations.	18.2.6	Prior to PEO	Ltr. No. 02-706

PEO: Period of Extended Operation

Item	Commitment	UFSAR Supplement Location	Implementation Schedule	Source
29	Inspect similar material/environment components, both within the system and outside the system, if aging identified in a location within a system cannot be explained by environmental/operational conditions at that specific location.	18.2.19	Prior to PEO	RAI B2.2.19-3
30	Supplement the NFPA pressure and flowrate testing credited in each LRA as part of the fire protection program activity with the work control process activity in order to manage aging effects for the fire protection system piping.	18.2.7	Prior to PEO	RAI B2.2.7-2

PEO: Period of Extended Operation

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10 SUPPLEMENTARY NOTES

11 ABSTRACT *(200 words or less)*

This safety evaluation report documents the Nuclear Regulatory Commission's (NRC's) review of Dominion Virginia Electric and Power Company's (Dominion's) applications to renew the operating licenses for North Anna Station, Units 1 and 2, and Surry Power Station, Units 1 and 2. The NRC's Office of Nuclear Reactor Regulation reviewed the North Anna and Surry power stations license renewal applications for compliance with the requirements of Title 10 of the Code of Federal Regulations, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and prepared this report to document the findings of the review.

On May 29, 2001, Dominion submitted two applications for renewal of Operating License Nos. NPF-4, NPF-7, DPR-32 and DPR-37, issued pursuant to Sections 103 and 104b of the Atomic Energy Act of 1954, as amended, for a period of 20 years beyond the current operating terms North Anna and Surry power stations are three-loop Westinghouse pressurized-water reactors nuclear steam supply systems designed to generate 2893 MW thermal and 2546 MW thermal, respectively

The NRC's project manager for the North Anna and Surry license renewal is Omid Tabatabai. Mr. Tabatabai may be reached at (301) 415-3738 or by writing to the License Renewal and Environmental Impacts Program, U.S. Nuclear Regulatory Commission, Mail Stop O-12D3, Washington, D.C.20555-0001.

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