3 AGING MANAGEMENT REVIEW

This section presents the staff's evaluation of the applicant's AMR. The applicant provided a proposed supplement to the Final Safety Analysis Report (FSAR Supplement) in Appendix A to the LRA, in accordance with 10 CFR 54.21(d). The purpose of the proposed FSAR supplement is to provide an appropriate description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses (TLAAs), so that any future changes to the programs or activities that may affect their effectiveness will be controlled under 10 CFR 50.59. By letter dated July 28, 2000, the staff issued RAIs related to Appendix A to the LRA. In response, by letter dated October 10, 2000, the applicant provided Appendix B to the LRA, which addressed many of the RAIs related to Appendix A of the LRA.

The staff issued Open Item 3.0-1 to ensure that the applicant's FSAR Supplement contained an adequate description of the programs and activities that have been credited for managing the effects of aging, and the evaluation of time-limited aging analyses (TLAAs) for the period of extended operation as required by 10 CFR 54.21(d). The staff reviewed the aging management program and TLAA descriptions provided by letter dated October 10, 2000, and the associated FSAR Supplement provided by letter dated September 5, 2001, and found that the FSAR Supplement provided by the applicant contains descriptions of these programs and activities adequate to satisfy 10 CFR Part 54 requirements. On the basis of the program descriptions provided by the applicant, the staff concludes that the FSAR Supplement contains sufficient information to adequately describe the content of the associated aging management programs and TLAAs and satisfies the requirements of 10 CFR 54.21(d). A condition will be included in the renewed license requiring the inclusion of the FSAR Supplement in the next UFSAR update, required by 10 CFR 50.71(e). Open Item 3.0-1 is closed.

In addition, the applicant committed to performing future inspections before the extended period of operation. These commitments are identified in the FSAR Supplement, submitted pursuant to 10 CFR 54.21(d), as part of the proposed aging management programs. Upon satisfactory completion of these activities prior to entering the extended period of operation (i.e., no later than August 6, 2014 for Unit 1, and June 13, 2018 for Unit 2), the staff can conclude that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29. A condition will be included in the renewed license requiring completion of these activities before the beginning of the period of extended operation.

3.1 Aging Management Programs

This section contains the staff's evaluation of the AMPs that are documented in Appendices A, B, and C of the LRA, and Appendix B of the applicant's October 10, 2000 submittal, and referenced as a part of the aging management for the various systems and/or structures of Plant Hatch. It should be noted that the staff's conclusions on its evaluations for some of these AMPs assume that they are implemented in conjunction with other relevant AMPs, as discussed in Sections 3.2 through 4.7 of this SER, for managing aging effects for a particular structure or component.

The staff's evaluation of the applicant's AMPs focused on program elements, rather than the details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended functions will be maintained in a manner that is consistent with the CLB throughout the period of extended operation, the staff evaluated 10 elements, including (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation processes, (9) administrative controls, and (10) operating experience.

The draft SRP-LR, released in 1997, describes the 10 basic elements of an effective AMP. The staff evaluated the proposed programs against the 10 elements. This SER describes the extent to which the 10 elements are applicable to particular components and aging effects. Based on experience with maintenance programs, the staff concludes that conformance with the applicable elements provides the basis to conclude that the programs are demonstrably effective at managing the associated aging effects.

The applicant indicated that elements (7) corrective actions, (8) confirmation processes, and (9) administrative controls for license renewal are in accordance with the site-controlled corrective actions program pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components (SCs) that are subject to an AMR. The staff's evaluation of the applicant's corrective actions program is discussed in Section 3.1.8 of this SER.

Aging Management of Seismic II/I Piping

By letter dated September 5, 2001, in response to Open Item 2.1.3.1-1, the applicant brought additional seismic II/I piping systems into the scope of license renewal. These piping systems consist of non-safety-related piping and supports whose failure could adversely impact nearby safety-related components, as well as non-safety-related piping that is attached to safety-related piping from the safety class break to the first seismic anchor, as credited in the associated seismic analysis. The applicant also provided information regarding the management of aging effects associated with these piping systems.

For non-safety-related piping that is attached to safety-related piping from the safety class break to the first seismic anchor, the applicant will use the same aging management programs (AMPs) as are used for the attached safety-related piping. If exceptions are identified in the future, where the credited programs do not adequately manage the aging effects, then the applicant will revise the aging management programs to assure proper aging management.

For non-attached seismic II/I piping systems, the applicant stated that the piping will be managed using the water chemistry control, Flow-Accelerated Corrosion (FAC), and Structural Monitoring Program AMPs, supplemented by one-time inspections, where applicable, as well as by the Corrective Actions Program. These programs are evaluated in Section 3.1 of this SER.

To manage loss of material due to various corrosion mechanisms, other than FAC, and cracking due to stress corrosion cracking of stainless steel in seismic II/I piping systems, the applicant stated that area walkdowns would also be performed to detect leaks in the piping. These walkdowns will be conducted as part of the existing structural monitoring program AMP. These walkdowns will use a "spaces" approach in the reactor, control, and diesel generator buildings, as well as the turbine building above the condenser system, and the intake structure.

The FAC program will be used to manage FAC in carbon steel, high-energy, seismic II/I lines (there are no low or moderate energy lines that are in scope and susceptible to FAC). In addition, appropriate chemistry controls will be used and one-time confirmatory inspections will be performed, as stated above.

On the basis of the additional information provided by the applicant in response to Open Item 2.1.3.1-1, the staff concludes that the aging management of the seismic II/I piping systems is adequate and provides reasonable assurance that safety-related structures, systems, and components will be adequately protected from the consequences of a failure in the seismic II/I piping systems.

3.1.1 Reactor Water Chemistry Control

3.1.1.1 Introduction

The applicant described its reactor water chemistry control AMP in Sections A.1.1, and C.1.2.1 of the LRA, and Section B.1.1 of the applicant's October 10, 2000 submittal. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) will be maintained in a manner that is consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

The components that are exposed to the reactor water environment and require aging management are contained in various commodity groups, including the reactor pressure vessel, reactor pressure vessel internals, Class 1 carbon steel components, Class 1 wrought and forged stainless steel components, Class 1 cast austenitic stainless steel components, non-Class 1 carbon steel components and non-Class 1 stainless steel components.

The management of aging effects by the reactor water chemistry control program for the components contained in the above commodity groups is described in Sections C.2.1.1.1, C.2.1.1.2, C.2.1.1.3, C.2.1.1.4, C.2.1.1.5, C.2.2.1.1 and C.2.2.1.2 of the LRA. The objective of the reactor water chemistry control AMP is to optimize the water chemistry to minimize the potential for degradation due to the aging effects. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that it will adequately manage the effects of aging caused by the reactor water environment in the plant throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.1.2 Summary of Technical Information in the Application

In the LRA, the applicant identified the following mechanical systems, which contain the components that are affected by the reactor water chemistry:

- reactor assembly system
- nuclear boiler system
- reactor recirculation system
- high-pressure coolant injection system
- reactor core isolation cooling system
- main condenser system
- electro-hydraulic control system

The details of these systems are described in Section 2.3 of the LRA.

The applicant evaluated the potential aging effects requiring management for the components that are exposed to the reactor water environment. The following aging effects are applicable to these components:

- loss of material as a result of general corrosion, crevice corrosion and pitting
- cracking as a result of stress corrosion cracking and intergranular attack (IGA)

The control of reactor water chemistry is accomplished in accordance with Electric Power Research Institute (EPRI), TR-103515, "BWR Water Chemistry Guidelines."

3.1.1.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's reactor water chemistry control program to ensure that the effects of aging on components exposed to reactor water will be adequately managed, so that the functions will be maintained consistent with the CLB for the period of extended operation for all components in a reactor water environment.

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the LRA regarding the applicant's demonstration of the reactor water chemistry control program to ensure that the effects of aging attributable to the reactor water chemistry will be adequately managed, so that the intended functions will be maintained consistent with the CLB for the period of extended operation for all components in the systems included in the scope of the program. After completing the initial review, by letter dated July 28, 2000, the staff issued several RAIs. By letter dated October 10, 2000, the applicant responded to the staff's RAIs.

The components exposed to the reactor water environment are made of carbon steel, low-alloy carbon steel, austenitic stainless steel, and nickel-based alloys. The aging effects to be managed by the reactor water chemistry control program are loss of material and cracking. Loss of material is attributable to pitting, crevice corrosion, and general corrosion occurring mainly in carbon steel. Cracking is due to stress corrosion cracking (SCC) and intergranular (IGA) in austenitic stainless steels and nickel-based alloys.

The IGA is considered a precursor for the SCC and provides the sites for crack initiation. The SCC consists of intergranular stress corrosion cracking (IGSCC), transgranular stress corrosion cracking (TGSCC), and irradiation assisted stress corrosion cracking (IASCC). The mechanisms of these aging effects that could be managed by the subject program are discussed in Section C.1.2 of the LRA. The aging effects are caused by the presence of excessive detrimental impurities (such as chlorides and sulfates) and oxidizing species in the reactor water. The staff's review did not identify any other aging effects that may be induced by the reactor water environment.

The applicant's reactor water chemistry control program is predicated on the guidance provided in EPRI TR-103515, "BWR Water Chemistry Guidelines." In the staff's RAIs regarding program elements that deviate from the referenced EPRI guidelines, the applicant indicated that this program is currently being updated to meet the guidance of EPRI TR-103515, Revision 2. The staff noted that EPRI TR-103515, Revision 2, has not been reviewed by the staff for generic use. The staff requested that the applicant clarify the differences between Revision 1 and Revision 2 of EPRI TR-103515, so the staff can determine whether the provisions of Revision 2 are acceptable. This was identified as Open Item 3.1.1-1.

By letter dated June 5, 2001, the applicant responded to the open item, stating that, as discussed in its response to RAI 3.1.1-2, Plant Hatch is committed to meeting the chemistry control parameters specified for RCS chemistry contained in EPRI TR-103515. The applicant identified, as a point of information, the applicable revision of the EPRI document which was current at the time the LRA was submitted, and noted that the program was being updated to a later revision of the document. The applicant believes, and the staff agrees, that it is important to maintain the flexibility to modify plant chemistry control procedures based on the best industry guidance developed from the collective operating experience of similar reactors. Therefore, over time, the applicant expects to revise the plant chemistry procedures to reflect changes in industry guidance as reflected in the EPRI control parameters.

As part of the response to Open Item 3.1.1-1, the applicant also discussed the significant differences between Revision 1 and Revision 2 of EPRI TR-103515. The first relates to the additional consideration of the beneficial effects of operation with hydrogen water chemistry (HWC) or with HWC with noble metal chemistry addition (NMCA). Revision 2 of EPRI TR-103515 provides an additional table (4-5b) which allows relaxation of the power operation Action Level 3 (AL3) values for chlorides and sulfates from 100 ppb to 200 ppb when HWC is in service and measured electrochemical potential (ECP) values are less than -230 mV. Currently, Plant Hatch operates in accordance with Revision 2 of the EPRI guidelines and current sampling and monitoring procedure allows for higher AL3 chloride and sulfate values under HWC. This additional flexibility is warranted based on the increased protection of reactor coolant system and reactor assembly components provided by HWC or HWC with NMCA.

The second significant difference between Revision 1 and Revision 2 of the EPRI guidelines involves the allowance in Revision 2 for monitoring of chlorides and sulfates on less than a daily basis, if appropriate, based on site-specific resource allocation needs. This flexibility in monitoring frequency is acceptable when adequately justified and supported by the conductivity values and/or chemistry trends that assure that Action Level 1 limits will not be exceeded.

On the basis of the information provided by the applicant in response to this open item, the staff concludes that the applicant should be allowed to maintain the flexibility to modify chemistry control procedures in response to new or updated industry information, and that the differences between Revision 1 and Revision 2 of the EPRI guidelines provide this flexibility. Therefore, the staff considers Open Item 3.1.1-1 closed.

Program Scope

The objective of the program is to mitigate the aging effects that are attributable to loss of materials and cracking. The components in the relevant commodity groups and systems that are exposed to the reactor water environment and require aging management by this program are listed in Section C.2 of the LRA. The staff finds that the scope of the subject AMP is adequate because it applies to components that are exposed to the reactor water environment.

Preventive or Mitigating Actions

The subject program controls the fluid purity and composition of the reactor water in the reactor coolant system and other systems, such as condensate/feedwater cycle, and the RWCU system. This is achieved through the use of filters/demineralizers that limit impurities within the feedwater, and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core.

The staff finds that the mitigation methods are acceptable because they are effective in minimizing the aging effects in the affected components.

Parameters Monitored or Inspected

The subject program monitors coolant conductivity, as well as sulfate and chloride concentrations. Currently, when HWC is in service, ECP is also monitored. The staff finds that the monitoring of these parameters is adequate to determine the quality of the reactor water.

Detection of Aging Effects

The applicant stated that the reactor water chemistry control is a mitigative activity and, as such, is not intended to directly detect age-related degradation of the affected components. The staff concurs with the applicant's statement.

Monitoring and Trending

The subject program does not monitor or trend age-related component degradation. However, the BWR water chemistry guidelines provide guidelines for data collection and trending methodologies for evaluation of reactor water chemistry control parameters. The conductivity is monitored continuously, and the chloride and sulfate concentrations are monitored daily. Currently, ECP is monitored continuously when HWC is in service. The staff finds that the monitoring and trending of the reactor water chemistry control parameters based on BWR water chemistry guidelines will identify deterioration of the reactor water chemistry.

Acceptance Criteria

The applicant stated that the acceptance criteria for the reactor water chemistry control parameters are founded on those provided in the BWR water chemistry guidelines. The acceptance criteria for the reactor water chemistry control parameters vary with the plant operating modes (cold shutdown, startup/hot shutdown, or power operation) and the water chemistry condition (normal water chemistry or HWC). In Section B.1.1 of the LRA, the applicant identified the minimum reactor water control parameters (conductivity < 0.30μS/cm, chlorides < 5 ppb and sulfates < 5 ppb) for action level 1 during normal power operation and referenced the BWR water chemistry guidelines as its basis.

Operating Experience

The major age-related component degradation in the reactor water environment is attributable to IGSCC in austenitic stainless steel materials. The applicant identified environmentally induced cracking, IGSCC in instrument penetrations, core spray sparger, and various components in the jet pump, core shrouds and recirculation system piping. These degraded components were either repaired or replaced. One of the key contributors to SCC degradation is the content of oxidizing species in the reactor water. The applicant installed HWC equipment in both units to reduce the content of oxidizing species in the reactor water to minimize the aging effect of IGSCC in the affected components. The applicant implemented NMCA to Unit 1 during the 1999 refueling outage and to Unit 2 during the 2000 refueling outage. The implementation of NMCA would further reduce the content of oxidizing species in the reactor water. The staff concludes that the applicant's reactor water chemistry control program will adequately manage the referenced aging effects, so that the structure and component intended functions will be maintained during the period of extended operation.

The staff notes that in its response to RAI 3.1.1-2, the applicant committed to meet the reactor water chemistry control parameters provided in the BWR water chemistry guidelines, but did not commit to a specific acceptable water chemistry mode. This is acceptable because the BWR water chemistry guidelines allow for both HWC and normal water chemistry operation. However, this would impact the applicant's in-service inspection (ISI) program. As delineated in BWRVIP-75, "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules (NUREG-0313)" and BWRVIP-62, "Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection," the extent and frequency of the required IGSCC inspection for those affected components depends on the mode of the reactor water chemistry operating condition.

3.1.1.4 Conclusions

The staff has reviewed the information in Section A.1.1, "Reactor Water Chemistry Control," and Section B.1.1, "Reactor Water Chemistry Control," of the LRA, and the applicant's responses to the staff's RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that, in conjunction with other AMPs, the effects of aging associated with SCs that are exposed to a reactor water environment will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2 Closed Cooling Water Chemistry Control

3.1.2.1 Introduction

The applicant described its closed cooling water (CCW) chemistry control AMP in Sections A.1.2, B.1.2, and C.1.2.3 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) of systems that are exposed to the CCW environment will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2 Summary of Technical Information in the Application

In Sections A.1.2 of the LRA, and Section B.1.2 of the applicant's October 10, 2000 submittal, the applicant describes the CCW chemistry control program, which manages, in part, the aging effects of stainless steel, carbon steel, and copper-based alloy components that are exposed to the CCW environment. The makeup water for this system is clean, deionized water that is exclusively provided by the demineralized water system.

The applicant stated in the LRA that the components exposed to the CCW environment are found in the reactor building closed cooling water system (RBCCW) and the primary containment chilled water system (Unit 2 only).

3.1.2.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding CCW chemistry control program to ensure that the effects of aging on components exposed to CCW will be adequately managed, so that the functions will be maintained consistent with the CLB for the period of extended operation for all components in a CCW environment.

Program Scope

The CCW chemistry controls are applied to the RBCCW system and the primary containment chilled water system (Unit 2 only), which include stainless steel, carbon steel, and copper-based alloy components. The CCW chemistry control program is applied to all closed cycle cooling water systems; however, only limited parts of these systems are within the scope of license renewal since these systems are not vital to safe shutdown of the plant under normal or accident conditions. The staff finds it appropriate and acceptable to include these systems in this AMP since these portions are in scope to maintain primary containment integrity.

Preventive or Mitigative Actions

The CCW chemistry control program is designed to mitigate and prevent age-related degradation (loss of material through corrosion) by controlling fluid purity and composition. Specifically, this program provides for the addition of corrosion inhibitors and biocides. Currently, the applicant adds nitrite/molybdate as a ferrous alloy corrosion inhibitor and tolytriazole (TTA) as a copper alloy inhibitor to promote protective oxide layer formation on surfaces. Although the source of makeup water for this system is clean, deionized water, biological contamination of this closed system may occur from in-leakage and/or maintenance activities. Therefore, EPRI-recommended biocides (currently isothiazolone and glutaraldehyde) are added to the water to control the formation of microbe populations. In the event of elevated chloride concentrations, contributed by the addition of corrosion inhibitors and biocides, the system is fed and bled with demineralized water, or an engineering evaluation is performed to insure that no long-term aging effects will result.

The staff finds it appropriate and acceptable to treat the cooling water system with these chemical additions to preclude the internal loss of material.

Parameters Inspected or Monitored

The application states that EPRI TR-107396, "Closed Cooling Water Chemistry Guideline," provides the basis for monitoring closed cooling water to ensure adequate chemistry control at Plant Hatch. This guideline provides several treatment options and includes control parameters such as pH and corrosion inhibitor concentrations. Diagnostic parameters include biocide, ammonia, chloride, and sulfate concentrations; microbe populations; and conductivity. The RBCCW system is equipped with carbon steel corrosion coupons,which are periodically analyzed to verify the effectiveness of the corrosion inhibitor system.

The staff finds that the monitoring of these parameters is appropriate and acceptable to maintain he effectiveness of this AMP.

Detection of Aging Effects

The application states the CCW chemistry control program is a mitigative activity,which is not intended to directly detect age-related degradation of components within the scope of this program. The staff agrees that the implementation of this program does not provide information directly related to the degradation of the specific material,and that there is no need to do so because this program, in conjunction with other AMPs, provides a means of mitigating or preventing age-related degradation.

Monitoring and Trending

The application states that the CCW chemistry control program does not directly monitor or trend age-related degradation and is not credited for such; however, the EPRI document provides the basis for trending, tracking, and evaluating CCW chemistry. The applicant notes that engineering personnel assist in performing evaluations of the structural integrity of the in-scope plant systems and, when necessary, chemistry modification is performed. These evaluations involve the identification of sources of raw-water in-leakage and evaluations to limit and prevent future chemistry excursions in the CCW system. The staff agrees that there is no need to directly monitor or trend age-related degradation, and finds that the applicant's implementation of guidelines from the EPRI document is appropriate and conservative.

Acceptance Criteria

The application states that the EPRI document provides the basis for the related to sulfates, chlorides, pH, Na_2MoO_4, $NaNO_2$, and TTA. In addition, the applicant monitors bacteria populations monthly, and weighs carbon steel corrosion coupons semiannually.

The staff finds that the applicant's acceptance criteria, which are founded on the EPRI document, validate the effectiveness of this chemistry control AMP and ensure that the corrosion rates occurring within the CCW systems are not significant. Therefore, the staff concludes that the acceptance criteria are appropriate and adequate to ensure that the aging effects of components exposed to component cooling water are effectively managed during the period of extended operation.

Operating Experience

The application states that the CCW chemistry has evolved as a result of increased industry research, operating experience, and specific issues associated with chemical additions and testing methods. In the past, CCW treatments consisted of molybdates only because nitrite additions were contributing to bacteria population growth. However, the molybdates consumed dissolved oxygen in the system, and left the carbon steel surfaces vulnerable to corrosion. Plant Hatch returned nitrites to the system, which effectively corrected the corrosion issues associated with using molybdates alone. Plant Hatch resolved the issue of increased bacteria population growth by adding new biocides. While these biocides were effective in controlling bacteria population growth, this addition increased chloride concentrations. In response to this increase, a bleed and makeup process using demineralized water was used in the past to reduce the chloride concentrations. The applicant makes note that the corrosion coupon data is currently well within the limits recommended by industry standards.

Given the applicant's operating history and the industry-wide use of this program, the staff finds that the CCW chemistry control program will adequately manage the aging effects of components that are exposed to the CCW environment.

3.1.2.4 Conclusions

The staff has reviewed the information in Section A.1.2, "Closed Cooling Water Chemistry Control," Section B.1.2, "Closed Cooling Water Chemistry Control," and Section C.1.2.3 of the LRA, and the applicant's responses to the staff's RAIs. On the basis of its review, the staff concludes that, in conjunction with other AMPs, the applicant has demonstrated that the effects of aging associated with structures and components exposed to a CCW environment will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.3 Diesel Fuel Oil Testing

3.1.3.1 Introduction

The applicant described its diesel fuel oil testing program in Sections A.1.3, C.2.2.7.1, and C.2.2.7.2 of the LRA and Section B.1.3 of the applicant's October 10, 2000 submittal. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on components in systems exposed to a fuel oil environment will be adequately managed so that intended function(s) will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.3.2 Summary of Technical Information in the Application

The applicant specified that the diesel fuel testing program applies to the emergency diesel generator fuel oil storage tanks, fuel oil day tanks, and the associated transfer piping and other components. It also covers the fire pump diesel fuel oil storage tanks and the associated piping and other components in the fire protection system included in the LRA scope. Tables 3.2.4-18 and 3.2.4-19 of the LRA identify the components.

The applicant evaluated aging effects for the components that are subject to an AMR and determined that the aging effects of the components remaining within the scope of license renewal and exposed to diesel fuel oil containing accumulated water and additives are caused by (1) loss of material caused by general corrosion, galvanic corrosion, crevice corrosion, pitting and microbiologically influenced corrosion (MIC), (2) cracking due to thermal fatigue.

In the LRA, the applicant identified only one AMP. The diesel fuel oil testing activities manages the corrosive effects of diesel fuel oil, while cracking of the piping due the thermal fatigue is adequately addressed by a TLAA (see Section 4.2.3 of this SER). The corrosive effects of diesel fuel oil are managed by the diesel fuel oil testing program, which consists of two elements:

- regularly checking diesel fuel oil storage and day tanks associated with the emergency diesel generators and the fire pump diesels for the presence of water, verifying that the total particulate concentration is within acceptable limits, and removing accumulated water

- sampling new fuel oil before off loading from the delivery vehicle, and introducing an additive which minimizes growth of microorganisms that could induce MIC

The program for managing cracking of piping caused by thermal fatigue is generically addressed in the TLAA program in Section 4.2 of the LRA. The staff's review of this TLAA can be found in Section 4.2 of this SER. The applicant concluded that these programs will manage aging effects in such a way that the intended function of the components of the diesel fuel oil storage and transfer systems will be maintained consistent with the CLB under all operating conditions during the period of extended operation.

3.1.3.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's diesel fuel oil testing program to ensure that the effects of aging on components exposed to fuel oil will be adequately managed, so that the functions will be maintained consistent with the CLB for the period of extended operation for all components in a fuel oil environment.

The environment in the diesel fuel oil storage and transfer system consists of the fuel oil, which may contain accumulated water and be contaminated with some impurities. Although fuel oil in its pure form is noncorrosive to metals, the presence of water, naturally occurring contaminants, or some fuel additives can create a corrosive environment. In the emergency diesel fuel storage and transfer systems, the components included within the scope of license renewal and exposed to this environment are constructed from carbon steel and stainless steel. These components are subject to loss of material as a result of general corrosion, galvanic corrosion, crevice corrosion, pitting, MIC, and cracking as a result of thermal fatigue. However, operating experience in several plants indicated an extremely low incidence of corrosion failure of the components exposed to diesel fuel oil. The recorded incidents were primarily related to clogging of strainers with sediments and degraded oil. At Plant Hatch, the deficiencies in the diesel fuel oil supply system with age-related implications were limited to unacceptable sediment and water levels in the diesel fuel oil storage tanks, and these deficiencies were successfully resolved. No significant aging attributable to thermal fatigue cracking is expected. However, since several components are potentially exposed to thermal fatigue, the applicant included this aging effect in the LRA.

On the basis of the above discussion, the staff finds that there is reasonable assurance that the applicant has included all the plausible aging effects related to the diesel fuel oil system for aging management consideration.

Program Scope

The scope of the program includes emergency diesel generator fuel oil storage and transfer systems, and fire pump diesel fuel oil storage tanks, and the associated systems containing structures and components for which age-related effects were identified. The staff finds that all the relevant systems were included in the program.

Preventive or Mitigating Actions

Regular checking for the presence of water, particulates, and other contaminants is performed in these systems, and accumulated water is removed. Also, in order to prevent introduction of contaminants into the diesel fuel oil system, new oil is sampled before it is introduced into the storage tanks. During the off-loading, a biocide is added to minimize corrosion attributable to MIC. The staff finds that these procedures are adequate because they include all the activities needed to mitigate age-related effects in SCs that are within the scope of license renewal.

Parameters Monitored or Inspected

The staff finds that inspection for water, particulates, and other contaminants in the storage tanks, and sampling new fuel oil for contaminants before its introduction into the tanks, will give sufficient protection against formation of corrosive environments that could cause damage to in-scope SSCs.

Detection of Aging Effects

The diesel fuel oil testing program, like the various chemistry control programs in effect at Plant Hatch, is a mitigative activity which is not intended to directly detect age-related degradation. The implementation of this program does not provide information directly related to the degradation of the structures and components within the scope of this program. The applicant does not take credit for such a system. Also, water in the fuel oil will be in contact with the tank bottom, possibly causing corrosion. The diesel fuel oil testing program will not be able to detect such degradation. Therefore, the staff concludes that a one-time inspection program is warranted for the diesel fuel oil tanks to verify tank bottom thickness. The addition of a one-time inspection program for the tanks would be consistent with the applicant's approach for other chemistry control programs at Plant Hatch. For example, the torus submerged components inspection program complements the applicant's suppression pool chemistry control. Also, the condensate storage tank inspection complements the applicant's demineralized water and condensate storage tank chemistry control program. The staff requested that the applicant provide the specific attributes of an inspection program, consistent with other one-time inspections (e.g., inspection scope, inspection technique, acceptance criteria, etc.). This was identified as Open Item 3.1.3-1.

By letter dated June 5, 2001, the applicant provided a response to this open item. The applicant stated that, since the license renewal application was submitted, one of the four buried, 40,000-gallon emergency diesel generator (EDG) fuel oil storage tanks (FOST) has been inspected. When Tank 1A was drained for cleaning during the last outage, the applicant took this opportunity to conduct aging inspections. On the basis of the results obtained through visual examination and ultrasonic testing (UT), the applicant concluded that significant wall thinning has not occurred in the Plant Hatch EDG FOSTs and that no aging management activities are required.

The Plant Hatch EDG FOSTs are constructed of 0.5 inch plate steel. Ultrasonic testing, covering 144 points along the lower portions of the tank, indicated that wall thickness was consistently between 0.500 and 0.524 inches. In no case was a reading taken less than 0.5 inches. The applicant believes that these results are representative of the other four tanks, since they are all the same material and they all have the same internal and external environments.

Prior to performing the UT, visual inspections were conducted of the "as-found" conditions. Very little corrosion was noted in the tank airspace. A thin adherent layer of general corrosion was identified in a small area. That small amount of surface corrosion was removed during cleaning.

Plant Hatch has five 40,000 gallon underground diesel fuel oil tanks with each one, as required by technical specifications, containing a minimum of 33,320 gallons. Three of these underground tanks (in conjunction with the associated day tanks) are sufficient to meet the 7-day supply requirement of two diesel generators at full load. The tank system has the ability to transfer fuel oil between tanks. Thus, the failure of any one tank would not prevent adequate plant response to a design basis accident. The Plant Hatch UFSAR contains the results of this failure analysis.

The FOSTs are checked monthly by technical specifications for level to assure that the 33,320-gallon requirement is maintained in each tank. Level can be checked either manually or by level indication in the main control room. Thus, any significant leak that could result in a level reduction over a short period of time would be observed. As stated in the UFSAR, there are sufficient fuel oil sources around Plant Hatch site to provide assurance that fuel oil can be obtained within 24 hours if necessary. Thus, there is assurance of an adequate EDG fuel oil supply if one tank experiences a substantial leak.

The Plant Hatch "Combined Oil / PCB and Hazardous Substance Spill Prevention, Control and Countermeasure and Spill Contingency Plan" would address Plant Hatch actions if a tank were to experience a leak. The Plan was prepared in accordance with the provisions of the Environmental Protection Agency's 40 CFR regulations and would be used to contain and clean up any spilled oil.

In summary, the design of the FOSTs and the operating experience to date suggests that corrosion is not a concern either on the exterior or the interior of these tanks. If at some point in the future, operating experience were to suggest otherwise, appropriate changes to plant programs would be made to address the issue. There are sufficient measures to detect a significant leak from these tanks. Leaks from these tanks are not a safety concern but are an environmental concern and would be addressed by the Plant Hatch spill and countermeasure program.

In addition to the EDG FOSTs, the fire pump diesel fuel oil storage tanks are also in scope for license renewal. The internal environment of these smaller tanks is similar to the internal environment of the EDG FOSTs, each tank having a diesel fuel oil volume and an air vapor space. However, the fire pump diesel fuel oil storage tanks are not buried. They are above ground and are painted. Thus, the external environment is at least as benign as the external environment for the buried EDG FOSTs. In summary, the applicant stated that the FOST visual and UT inspection results already obtained are responsive to the issue raised in the open item and substantiate the LRA conclusion that loss of material is not an aging effect requiring management during the renewal term for either the EDG FOSTs or the fire pump diesel fuel oil storage tanks.

On the basis of its review of the additional information provided by the applicant in its letter dated June 5, 2001, the staff concludes that the applicant has performed a one-time inspection of the internal surfaces of one of the FOSTs, has adequately determined that age-related degradation of the tank bottoms has been minimal, and that significant age-related degradation of the FOSTs is unlikely during the period of extended operation. Open Item 3.1.3-1 is closed.

Monitoring and Trending

There is no monitoring and trending aspects to the diesel fuel oil testing program, nor did the staff identify a need for such.

Acceptance Criteria

The acceptance criteria specified by the applicant requires less than 0.05 percent by volume of water and sediments to be present in the new fuel oil shipments, and the stored fuel oil should have no more than 10 mg/liter of particulates. In addition, a three-level composite sample from the emergency diesel generator storage tank and middle sample from the fire pump diesel oil storage tank should have water and sediment concentration not exceeding 0.05 percent by volume. The concentration in a bottom sample from these tanks should not exceed 0.1 percent of water and sediment by volume. The staff concurs with the applicant that these criteria will ensure that the aging effects in the diesel fuel oil system will be properly managed.

Operating Experience

Inspection of the industry-wide data showed an extremely low incidence of failure of components exposed to fuel oil. The inspection did not identify any incidents caused by corrosion and the only deficiency reported in several plants was clogging of strainers with sediments and degraded oil. A review of the applicant's data for the past 5 years has uncovered several deficiencies. These deficiencies were screened to determine which of them were potentially related to aging. The results of the screening have indicated that the deficiencies were limited to instances of unacceptable sediment and water levels within the diesel fuel oil storage tanks. However, they were promptly restored to acceptable limits through the corrective actions program. No instances of component failure attributable to age-related degradation were identified. As discussed above under the element "Detection of Aging Effects," this mitigative program should be supplemented by a one-time inspection to provide direct evidence of the absence of corrosion caused by either external or internal environments.

3.1.3.4 Conclusions

The staff has reviewed the information in Sections A.1.3, "Diesel Fuel Oil Testing," C.2.2.7.1, and C.2.2.7.2 of the LRA, Section B.1.3 of the applicant's October 10, 2000 submittal, and the applicant's responses to the staff's RAIs. On the basis of its review, the staff concludes that, in conjunction with other AMPs, the applicant has demonstrated that the effects of aging associated with structures and components exposed to a fuel oil environment will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.4 Plant Service Water and RHR Service Water Chemistry Control

3.1.4.1 Introduction

The applicant described its plant service water and RHR service water (PSW and RHRSW) chemistry control AMP in LRA Sections A.1.4, and C.1.2.4 and Section B.1.4 of the applicant's October 10, 2000 submittal. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging of components in systems exposed to PSW and RHRSW will be adequately managed so that intended function(s) will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.4.2 Summary of Technical Information in the Application

In LRA Section A.1.4 and Section B.1.4 of the applicant's October 10, 2000 submittal, described the PSW and RHRSW chemistry control program, which manages, in part, the aging effects of carbon steel, cast iron, copper alloy, and stainless steel components exposed to the PSW and RHRSW system environment. The PSW and RHRSW are drawn from the Altamaha River. The components exposed to a PSW and RHR service water environment are found in the PSW system and the residual heat removal system.

3.1.4.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's PSW and RHRSW chemistry control program to ensure that the effects of aging on components exposed to PSW and RHRSW will be adequately managed, so that the functions will be maintained consistent with the CLB for the period of extended operation for all components in PSW and RHRSW environments.

Program Scope

PSW and RHR service water chemistry controls are applied to the PSW system, RHRSW system, and traveling water screens/trash rack system, which include carbon steel, copper alloy, gray cast iron, cast austenitic stainless steel, stainless steel clad carbon steel and stainless steel components. The staff finds it appropriate and acceptable to include these systems in this AMP.

The staff found a discrepancy regarding whether the PSW and RHRSW chemistry control program manages aging effects associated with valve bodies in the traveling water screens/trash racks system. By letter dated January 31, 2001, the applicant clarified that the isolation valve in the screen wash system credits the PSW and RHRSW chemistry control program. Specifically, a single isolation valve in the screen wash line, credited by the FHA safe shutdown list, credits this chemistry program to mitigate the effects of aging.

Preventive or Mitigative Actions

The PSW and RHRSW chemistry control program is designed to mitigate and prevent age-related degradation (loss of material through corrosion) by controlling the biological growth in the service water systems. Specifically, this program adds sodium hypochlorite alone or in conjunction with sodium bromide, and is coordinated with the periodic operation of the RHRSW to maximize chemical treatment.

The staff finds it appropriate and acceptable to treat the service water system with these chemical additions to preclude the internal loss of material through biofouling.

Parameters Inspected or Monitored

The application states that during PSW system chlorination and bromination, free available oxidant (FAO) concentration is periodically monitored at the PSW discharge to the circulating water flume to ensure program efficiency. The plant's National Pollutant Discharge Elimination System (NPDES) permit governs the levels of discharged measurable chlorine, FAO, and total residual oxidant levels.

The staff finds that monitoring of these parameters is appropriate and acceptable in determining the effectiveness of this AMP. Specifically, the FAO concentration at the discharge is a good indicator of the effectiveness of the chlorination and bromination in controlling the biofouling.

Detection of Aging Effects

The application states the PSW and RHRSW chemistry control program is a mitigative activity which is not intended to directly detect age-related degradation of components within the scope of this program. The staff agrees that the implementation of this program does not provide information directly related to the degradation of the specific material and that there is no need to do so because this program, in conjunction with other AMPs, provides a means of mitigating or preventing age-related degradation.

Monitoring and Trending

The application states that chemical additions under this AMP are monitored routinely through the treatment cycles which occur 5 times per week for 6 to 12 hours. During this treatment, FAO is monitored, which ensures that the chemical additions are at levels that result in program effectiveness and system is operating consistent with the requirements and limitations of the plant NPDES permit.

The staff finds that the frequency of monitoring the established chemistry parameters is acceptable and appropriate to ensure that the aging effects of components within the scope of this program are managed.

Acceptance Criteria

The application states that the site NPDES permit provides diagnostic parameters and associated limitations for effective control of plant discharges. In addition, the permit provides for additional chemical monitoring every fifteen minutes until no residual oxidant is detected. These sample results are reported quarterly to the State of Georgia Department of Natural Resources.

The staff finds that the applicant's criteria, which are founded on the applicant's NPDES permit, are acceptable and appropriate to ensure that a deviation from these parameters can be corrected to ensure that component functions of the components will be maintained during the period of extended operation.

Operating Experience

The application states that the plant has experienced biofouling problems with algae and has found evidence of the Asiatic clam. These sources of biofouling have yet to impair the effectiveness of components within the scope of this AMP. The applicant currently implements the chemical treatments consistent with the recommendations of Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and incorporates industry guidance, vendor recommendations, and plant-specific experience. The applicant states that periodic evaluation of this chemical treatment optimizes control of biofouling while maintaining discharge limits within the NPDES permit. Given the applicant's operating history and the industry-wide use of this program, the staff finds that the PSW and RHRSW chemistry control program will adequately manage the aging effects in the PSW system, RHRSW system, and the traveling screens/trash racks system.

During a teleconference with the applicant on November 8, 2000, the staff noted that LRA Table 3.2.4-16 identifies the PSW and RHRSW chemistry control program as managing aging associated with valve bodies in the traveling water screens/trash racks system. However, the description of the PSW and RHRSW chemistry control program in LRA Section B.1.4 does not include the traveling water screens/trash racks system within the scope of the program. During the teleconference, the applicant committed to revise Section B.1.4 in the FSAR Supplement to include the traveling screens/trash racks system within the scope of the PSW and RHRSW chemistry control program. By letter dated January 31, 2001, the applicant clarified this formally.

3.1.4.4 Conclusions

The staff has reviewed the information in LRA Section A.1.4, of the LRA, "Plant Service Water (PSW) and Residual Heat Removal (RHR) Service Water Chemistry Controls," Section B.1.4, of the applicant's October 10, 2000 submittal, "Plant Service Water (PSW) and Residual Heat Removal (RHR) Service Water Chemistry Controls," and Section C.1.2.4, the applicant's responses to the staff's RAIs, and additional information submitted by letter dated January 31, 2001. On the basis of its review, the staff concludes that, in conjunction with other AMPs, the applicant has demonstrated that the effects of aging associated with structures and components in systems exposed to PSW and RHRSW will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.5 Fuel Pool Chemistry Control

3.1.5.1 Introduction

The applicant described its fuel pool chemistry control AMP in LRA Sections A.1.5,C.2.6.5, and C.2.6.6 and Section B.1.5 of the applicant's October 10, 2000 submittal. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on structures and components in systems exposed to a fuel pool environment will be adequately managed so that intended function(s) will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.5.2 Summary of Technical Information in the Application

The fuel pool chemistry control activities mitigate aging in the fuel pool liner and associated components through the control of fluid purity and composition. The basis for the methodology employed to maintain fuel pool chemistry parameters within acceptable limits is provided in EPRI document TR-103515, "BWR Water Chemistry Guidelines." These activities are applicable to stainless steel liners for the spent fuel pool, spent fuel pool plugs, spent fuel pool gate, refueling canal, spent fuel pool racks, and miscellaneous steel inside the spent fuel pool. In addition, aluminum seismic restraints for the spent fuel pool racks are managed through these activities.

3.1.5.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's fuel pool chemistry control program to ensure that the effects of aging on components exposed to fuel pool water will be adequately managed, so that the functions will be maintained consistent with the CLB for the period of extended operation for all components in a fuel pool water environment.

Program Scope

Fuel pool chemistry control activities are applied to the fuel storage system, which includes the spent fuel pool liner, components, and racks.

Fuel pool chemistry control activities are applied to the fuel storage and refueling equipment systems, which include aluminum components.

The staff agrees that it is appropriate to include the systems listed above within the scope of fuel pool chemistry control activities.

Preventive or Mitigative Actions

Fuel pool chemistry control is designed to mitigate and prevent age-related degradation by controlling fluid purity and composition. Specifically, this program focuses on minimizing detrimental ionic species (such as sulfates, chlorides, and organic carbons) and conductivity. The staff finds that the control of these and other impurities, as provided in the EPRI document, can mitigate and prevent age-related degradation.

Parameters Inspected or Monitored

The application states that fuel pool water is sampled regularly for conductivity, chlorides and sulfates, and total organic carbons, as provided in the EPRI document. Fuel pool pH and filterable solids are also periodically monitored. The staff finds that monitoring these parameters is adequate and sufficient to mitigate age-related degradation of the materials in the spent fuel pool.

Detection of Aging Effects

The application states that the fuel pool chemistry control program is a mitigative activity which is not intended to directly detect age-related degradation of the fuel pool and associated internal structures. The staff agrees that the implementation of this program does not provide information directly related to the degradation of the specific material and that there is no need to do so because this program, in conjunction with other AMPs, provides a means of mitigating or preventing age-related degradation.

Monitoring and Trending

The application states that spent fuel pool chemistry parameters are maintained in accordance within the parameters set forth in Appendix B of the EPRI document. These parameters include sulfates, chlorides, conductivity, and total organic carbon which are monitored weekly as provided in the EPRI document. In addition, fuel pool pH and filterable solids are regularly monitored. The staff finds that the frequency of monitoring the established chemistry parameters is acceptable and appropriate to ensure that a deviation from the set parameters can be corrected in a timely manner.

Acceptance Criteria

The application states that the EPRI document provides diagnostic parameters and associated limitations for chemistry analyses. The staff finds that the criteria provided in the EPRI document are acceptable and appropriate for ensuring that a deviation from these parameters can be corrected to ensure that functions of the components are maintained during the period of extended operation.

Operating Experience

The application states that a review of the past 5 years has revealed no age-related deficiencies on the fuel pool or associated internal structures. Rare instances of minor fuel pool chemistry excursions have occurred but these instances have been determined not to be significant. In addition, the application states that the corrective actions program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences. Given the applicant's operating history and the industry-wide use of this program, the staff finds that the spent fuel pool chemistry control activities will adequately manage aging effects associated with the fuel pool for the period of extended operation.

3.1.5.4 Conclusions

The staff has reviewed the information in LRA Sections A.1.5, "Fuel Pool Chemistry Control," C.2.6.5, and C.2.6.6, Section B.1.5 of the applicant's October 10, 2000 submittal, and the applicant's responses to the staff's RAIs. On the basis of its review, the staff concludes that, in conjunction with other AMPs, the applicant has demonstrated that the effects of aging associated with structures and components in systems exposed to a fuel pool water environment will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.6 Demineralized Water and Condensate Storage Tank Chemistry Control

3.1.6.1 Introduction

The applicant described its demineralized water and condensate storage tank chemistry control activities in LRA Sections A.1.6 and C.2.2.2 and Section B.1.6 of the applicant's October 10, 2000 submittal. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on structures and components in systems exposed to demineralized water and condensate storage tank environments will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.6.2 Summary of Technical Information in the Application

The demineralized water and CST chemistry control activities are intended to mitigate aging by monitoring fluid purity and composition in the makeup water to multiple systems. The principal elements of these activities are regular sampling, results analysis and, when applicable, chemistry modification.

3.1.6.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demineralized water and CST chemistry control program to ensure that the effects of aging on components exposed to demineralized and CST water will be adequately managed, so that the functions will be maintained consistent with the CLB for the period of extended operation for all components in demineralized water and CST water environments.

Program Scope

The demineralized water and CST chemistry control is directly or indirectly monitored in the following systems:

B21-Nuclear Boiler
C11-CRD
E41-HPCI
E51-RCIC
P11-Condensate Transfer and Storage
R43-EDG
T23-Primary Containment

It is noted that while the demineralized water system proper is not within the scope of license renewal, several systems and components that receive makeup water from the demineralized water storage tank (DWST) are within the scope of license renewal. Therefore, the DWST chemistry control is an important aspect of aging management for the systems indicated above.

The staff finds the applicant's scope to be appropriate and acceptable, since these systems are monitored by the demineralized water chemistry control.

Preventive or Mitigative Actions

The staff finds that the control of detrimental ionic species and other impurities in demineralized water, as provided in the BWR water chemistry guidelines can mitigate and prevent age-related degradation. By controlling the water chemistry in the CST and DWST, the applicant reduces the potential for significant corrosion of plant systems and components exposed to a demineralized water environment. Therefore, the staff finds this approach acceptable.

Parameters Inspected or Monitored

The BWR water chemistry guidelines provide the basis for the monitored demineralized water chemistry parameters to ensure adequate chemistry control at Plant Hatch. The staff finds that monitoring these parameters is adequate and sufficient to mitigate age-related degradation of the systems and components exposed to a demineralized water environment.

Detection of Aging Effects

The application states that the demineralized water and CST chemistry control program is a mitigative activity which is not intended to directly detect age-related degradation of the systems and components exposed to a demineralized water environment. The staff agrees that the implementation of this program does not provide information directly related to the degradation of the specific material and that there is no need to do so because this program, in conjunction with other AMPs, provides a means of mitigating or preventing age-related degradation.

Monitoring and Trending

The application states that demineralized water chemistry control does not directly monitor or trend age-related degradation and as such is not credited to perform this attribute. However, the BWR water chemistry guidelines provide the basis for the methodology employed for periodic monitoring of demineralized water chemistry parameters at Plant Hatch. These parameters include sulfates, chlorides, total organic carbon, and silica, which are monitored weekly as recommended by the EPRI document. In addition, conductivity and pH are diagnostically monitored. The staff finds that the monitoring frequency identified in the BWR water chemistry guidelines is acceptable and appropriate to ensure that a deviation from the set parameters can be corrected within a timely manner.

Acceptance Criteria

The application states that the BWR water chemistry guidelines provide diagnostic parameters and associated limitations for chemistry analyses. In addition to the EPRI requirements, the applicant also diagnostically monitors pH and conductivity. The staff finds that the criteria provided in the EPRI document is acceptable and appropriate for ensuring that a deviation from these parameters can be corrected to ensure that intended functions of the components are maintained during the period of extended operation.

Operating Experience

The application states that a review of the past 5 years has revealed that no age-related deficiencies were found as a result of significant corrosion of system components. Rare instances of CST and DWST chemistry excursions have occurred, but these instances have been determined not to be significant. In addition, the EPRI TR-103515 guidelines for auxiliary systems incorporated the input of industry experts and utility experience. Therefore, the operation, according to the guidelines specified by these EPRI guidelines, ensures that pertinent industry issues were considered. Therefore, given the applicant's operating history and the industry-wide use of this program the staff finds that the demineralized water and CST chemistry control activities will adequately manage the aging effects associated with the CST and DWST for the period of extended operation.

3.1.6.4 Conclusions

The staff has reviewed the information in LRA Section A.1.6, "Demineralized Water and Condensate Storage Tank Chemistry Control," and Section B.1.6, "Demineralized Water and Condensate Storage Tank Chemistry Control," of the applicant's October 10, 2000 submittal. On the basis of its review, the staff concludes that, in conjunction with other AMPs, the applicant has demonstrated that the effects of aging associated with structures and components in systems exposed to demineralized water and CST environments will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.7 Suppression Pool Chemistry Control

3.1.7.1 Introduction

The applicant described its suppression pool chemistry control AMP in LRA Section A.1.7. The applicant supplemented the description of this AMP in Section B.1.7 of the applicant's submiital dated October 10, 2000. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on structures and components in systems exposed to a suppression pool environment will be adequately managed so that intended function(s) will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.7.2 Summary of Technical Information in the Application

In LRA Sections A.1.7 and B.1.7, the applicant describes an existing AMP, the suppression pool chemistry control program, that manages, in part, aging effects for various structures and components exposed to the suppression pool environment. The affected systems include nuclear boiler, residual heat removal, core spray, high-pressure coolant injection, reactor core isolation cooling, primary containment, and primary containment purge and inerting. The applicant lists the specific system structures and components that are exposed to the suppression pool environment in LRA Sections 3.2 and 3.3. These structures and components are fabricated from either carbon steel or stainless steel.

As discussed in LRA Section C.1.2.2, loss of material is an applicable aging effect that may affect both carbon steel and stainless steel structures and components through several corrosion mechanisms. These mechanisms include general corrosion, galvanic corrosion, crevice corrosion, pitting, MIC, and erosion corrosion. The applicant also considers cracking to be an applicable aging effect that may affect specific stainless steel components (that experience higher operating temperatures) as a result of stress corrosion cracking or intergranular attack. To mitigate these corrosion-related aging effects, the applicant relies on the suppression pool chemistry control program.

The suppression pool water (also called "torus water" in the LRA) contained within the torus consists of demineralized water supplied from demineralized water sources (such as the condensate storage tank). The applicant relies on chemistry controls to mitigate aging associated with corrosion in structures and components exposed to the suppression pool water by controlling the water purity and composition. The program consists of periodic sampling and testing of the suppression pool water for conductivity, chlorides, sulfates, and total organic compounds. The applicant stated that the program is found on the applicable portions of the EPRI BWR Water Chemistry Guidelines.

3.1.7.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's suppression pool chemistry control program to ensure that the effects of aging on components exposed to a suppression pool environment will be adequately managed, so that the functions will be maintained consistent with the CLB for the period of extended operation for all components in a suppression pool environment.

Program Scope

The applicant stated that the scope of this program included structures and components within the nuclear boiler (including safety relief valve tailpipes and associated supports), residual heat removal, core spray, high pressure coolant injection, reactor core isolation cooling, and primary containment purge and inerting systems, and primary containment (including the torus). The staff finds the program scope to be acceptable because the scope is comprehensive in that it includes all components exposed to the suppression pool water environment.

Preventive or Mitigative Actions

The program minimizes detrimental ionic species and conductivity in the suppression pool environment. The staff finds these actions acceptable because by minimizing ionic species and conductivity, one mitigates degradation as a result of corrosion.

Parameters Inspected or Monitored

The program monitors conductivity, chlorides, sulfates, and total organic carbons in accordance with the BWR water chemistry guidelines (EPRI TR-103515). The staff finds this acceptable because published literature and operating experience to date support the monitoring and control of these specific parameters to mitigate corrosion-related degradation.

Detection of Aging Effects

The applicant stated that the suppression pool chemistry control program is a mitigative activity which is not intended to directly detect age-related degradation. The staff agrees that the implementation of this program does not provide information directly related to the degradation of the structures and components within the scope of this program and that there is no need to do so because this program, in conjunction with other AMPs, provides a means of mitigating or preventing age-related degradation.

Monitoring and Trending

The applicant stated that the frequency of the suppression pool water sampling is on a quarterly basis, consistent with the EPRI guidelines. The staff finds this frequency to be acceptable because operating experience to date supports this frequency to be often enough to detect and correct anomalous chemistry conditions before there is a loss of intended functions. The applicant also stated that they monitor and trend the sampling results. Monitoring and trending provide important information about how a program is performing relative to acceptance criteria. Proactive monitoring and understanding of trending behavior allow for corrective actions to be taken prior to exceeding the acceptance criteria. Monitoring and trending of water chemistry parameters are also consistent with the EPRI BWR water chemistry guidelines. The staff therefore finds this approach to be acceptable.

Acceptance Criteria

The applicant applies the acceptance criteria consistent with those in the BWR water chemistry guidelines. The staff finds this acceptable because the acceptance criteria have low thresholds to allow for the early detection and correction of anomalous chemistry conditions.

Operating Experience

Operating experience provides the staff additional information about the acceptability of an AMP. The applicant reviewed plant deficiency cards over the past 5 years that showed that no age-related deficiency report had been written on the structures or components within the scope of license renewal for which suppression pool chemical control is credited. Suppression pool chemistry excursions have been rare. In the past 5-years, only minor excursions above the EPRI criteria have occurred. The applicant stated that none of these excursions was determined to be significant.

Additionally, the program follows the EPRI BWR water chemistry guidelines that incorporate the input of industry experts and utility experience and thus ensures the consideration of pertinent industry issues. These guidelines have been used by the industry for many years. Given the acceptable operating experience to date, the staff believes that this guidance has proven itself effective in minimizing corrosion-related degradation in the suppression pool water environment.

3.1.7.4 Conclusions

The staff has reviewed the information in LRA Section A.1.7, "Suppression Pool Chemistry Control" Section B.1.7, "Suppression Pool Chemistry Control" of the applicant's October 10, 2000 submittal, and the applicant's responses to the staff's RAIs. On the basis of its review, the staff concludes that, in conjunction with other AMPs, the applicant has demonstrated that the effects of aging associated with structures and components exposed to a suppression pool environment will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.8 Corrective Actions Program

3.1.8.1 Introduction

In LRA Section A.1.8, "Corrective Action Program" and Section B.1.8, "Corrective Actions Program" of the applicant's October 10, 2000 submittal, the applicant describes the aging management program credited for initiating corrective actions when age-related degradation is identified in structures and components subject to an AMR. The staff reviewed this AMP to determine if the applicant has included the attributes needed for an adequate AMP.

The license renewal applicant is required to demonstrate that the effects of aging on structures and components subject to an AMR will be adequately managed to ensure that their intended functions will be maintained consistent with the CLB of the facility for the period of extended operation. Therefore, those aspects of the AMR process that affect the quality of safety-related structures, systems, and components, are subject to the quality assurance (QA) requirements of Appendix B to 10 CFR Part 50. For non-safety-related structures and components subject to an AMR, the existing 10 CFR Part 50, Appendix B QA program may be used by the applicant to address the elements of corrective actions, confirmation process, and administrative controls.

3.1.8.2 Summary of Technical Information in the Application

LRA Section A.1.8 and Section B.1.8 of the applicant's October 10, 2000 submittal provide a brief description of the corrective actions program (CAP) and state that the CAP applies to all SSCs within the scope of license renewal. The CAP is also described as part of the applicant's Quality Assurance Program required by 10 CFR Part 50, Appendix B.

LRA Section A.1.8.1 states that the CAP is briefly described in Chapter 17 of the Plant Hatch Unit 2 UFSAR, and asserts that this process will be effective for correcting potential age-related degradation that may be discovered during the renewal term. The primary vehicle for initiating corrective action at the plant is the condition reporting process. Existing procedures include the necessary forms and instructions for reporting potential problems related to aging management of the SSCs that are within the scope of license renewal. Significant conditions adverse to quality require initiation of a special report. Significant occurrences are investigated to determine root cause, and actions are taken to preclude recurrence. Forms and guidance for root cause analysis are provided in Plant Hatch procedures and guidelines. Corrective actions are part of the QA program, as required for the Plant Hatch current license term under Criterion XVI of Appendix B to 10 CFR Part 50.

3.1.8.3 Staff Evaluation

During the scoping and screening audit conducted from June 12 through June 15, 2000, the applicant's implementation of the corrective actions process described in LRA Section 3.1.8 was reviewed by the staff.

Section C.2 of the LRA provides an AMR summary for each unique structure, component, or commodity group determined to require aging management during the period of extended operation. This summary includes identification of aging effects requiring management, aging management programs utilized to manage these aging effects, and attribute tables that demonstrate how the identified aging management programs manage aging effects. The staff found that the attributes identified for each AMR were consistent with those attributes described in Table A.1-1 of the draft SRP-LR. However, the Plant Hatch LRA does not describe each of these attributes and, therefore, the applicant was requested to provide this information in RAI 3.1.8-1, issued on July 28, 2000.

In its response to the staff's RAI dated October 10, 2000, the applicant confirmed that the description for each of the 10 attributes is the same as the description given in the draft SRP-LR. Section B to the submittal dated October 10, 2000, included a description of these attributes. The staff has reviewed the corrective actions, administrative controls, and confirmation process aging management program attributes described by the applicant in Section B to the RAI response and concluded that they are consistent with the description given in the draft SRP-LR and are, therefore, acceptable. Accordingly, RAI 3.1.8-1 is closed.

Section A.2 of the draft SRP-LR, requires a license renewal applicant to demonstrate that the effects of aging on structures and components subject to an aging management review will be adequately managed to ensure that their intended functions will be maintained consistent with the current licensing basis of the facility for the period of extended operation. Consistent with this approach, the applicant's aging management programs should contain the elements of corrective action, confirmation process, and administrative controls in order to ensure proper management of the aging programs.

LRA Section C.2 provides an aging management summary for each unique structure, component, or commodity group at Plant Hatch determined to require aging management during the period of extended operation. For the majority of these AMRs, corrective actions, confirmation process, and administrative controls are specifically addressed by reference to the applicant's CAP. However, LRA Section A.1.8, does not describe how the CAP program specifically addresses those three attributes for which credit is being sought. Therefore, in RAI 3.1.8-2, the applicant was requested to provide a description of how the CAP program specifically addresses these three attributes for the aging management programs at Plant Hatch during the period of extended operation.

In its October 10, 2000, response to the staff's RAI, the applicant stated that the LRA used the label "Corrective Actions Program" for a combination of plant activities that includes the plant's corrective actions program and portions of the plant's 10 CFR Part 50 Appendix B QA program. The applicant added that Appendix B to the RAI response provided a description of how this program addresses the attributes credited.

In Section B to its October 10, 2000, RAI response, the applicant provided a summary of aging management programs for license renewal. Under Section B.1 of the Section, the applicant stated the following:

> "The Corrective Actions Program is credited for the following four attributes for all aging management activities at Plant Hatch:
>
> - Attribute 7 - Corrective actions, including root cause determination and prevention of recurrence, are included.
> - Attribute 8 - Confirmation process is included.
> - Attribute 9 - Administrative controls should provide a formal review and approval process.
> - Attribute 10 - Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered."

Further, in Section B.1.8 of the submittal dated October 10, 2000, the applicant described in detail how corrective actions, confirmation process, and administrative control elements are to be met for all aging management programs at Plant Hatch. As described in Section B.1.8, the applicant has established and implemented a QA Program for Plant Hatch that conforms to the criteria set forth in 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants". The QA program addresses all aspects of quality assurance at Plant Hatch.

The two elements of the Plant Hatch QA program that are most pertinent to the aging management programs credited for license renewal are corrective actions and administrative controls. These elements are discussed in Chapter 17 of the Plant Hatch Unit 2 UFSAR, and are outlined below. Corrective action and administrative control requirements apply to all components within the scope of license renewal.

Program Scope

The plant condition reporting process applies to all plant systems and components within the scope of license renewal. Administrative controls are in place for existing aging management programs and activities and for the currently required portions of enhanced programs and activities. Administrative controls will also be applied to new programs and activities as they are implemented. As a minimum, these programs and activities are or will be performed in accordance with written procedures. Those procedures are or will be reviewed and approved in accordance with Plant Hatch's 10 CFR Part 50, Appendix B, QA Program.

The staff finds that the applicant has adequately identified that all structures, components, and commodity groups are within the scope of the CAP.

Preventive or Mitigative Actions

The CAP provides a means to correct conditions identified as being adverse to quality. There are no preventive or mitigative attributes specifically credited for this program. The staff finds that the CAP is not a preventive or mitigative activity and instead, corrects conditions found to be adverse to quality.

Parameters Inspected or Monitored

No specific parameters are inspected or monitored as part of this program. Generally, when parameters inspected or monitored by other plant programs indicate a condition adverse to quality, the CAP provides a means to correct the identified condition. The staff agrees that this program does not inspect or monitor parameters, nor should it.

Detection of Aging Effects

Detecting aging effects is not part of the CAP. The CAP provides a means to address the aging effects identified by other AMPs. The staff agrees that the purpose of this program is not to detect aging effects, but to provide corrective actions when other AMPs identify aging effects.

Monitoring and Trending

The corrective action process is monitored and trended to ensure that corrective actions taken are adequate and timely. Significant and in-significant conditions are trended. Plant Hatch monitors significant conditions that are adverse to quality (significant occurrence reports) and requires a formal cause determination and corrective actions to prevent recurrence. The staff finds that the CAP adequately monitors and trends significant conditions to identify and correct the adverse conditions in a timely manner.

Acceptance Criteria

The CAP does not include specific acceptance criteria for in-scope components. Generally, when the acceptance criteria of other AMPs are not met, the CAP provides a means to ensure appropriate corrective actions are taken. The staff agrees that the purpose of the CAP is to correct and restore components that do not meet acceptance criteria.

Corrective Actions

Corrective action is initiated following the determination of conditions adverse to quality, and documented as required by appropriate procedures. Various processes are used to identify problems requiring corrective action. The primary vehicle for initiating corrective action at Plant Hatch is the condition reporting process described in Section 17.2.15 of the Unit 2 UFSAR.

The various components of corrective action provide for timely corrective actions, including root cause determination and prevention of recurrence. The QA program provides control over activities affecting the quality of systems, structures, and components consistent with their importance to safety. In accordance with plant procedures, condition reports are analyzed for adverse trends. Any identified adverse trends are reported to the appropriate department for corrective action.

The staff finds the corrective action process acceptable, appropriate, and sufficient to identify and correct conditions adverse to quality in a timely manner.

Confirmation Process

As described in Section 17.2.15 of the Unit 2 UFSAR, condition reports are reviewed to determine the regulatory reportability and significance. Those items found to be significant conditions adverse to quality are also reviewed. Corrective actions taken for significant items are reviewed for assurance that appropriate action has been taken.

The staff finds that the confirmation process is adequate to ensure that corrective actions are appropriate and complete.

Administrative Controls

Activities affecting quality are prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and are accomplished in accordance with these instructions, procedures, or drawings. They contain appropriate acceptance criteria and documentation requirements for determining whether important activities have been satisfactorily accomplished. Site procedures establish review and approval requirements.

The staff finds the administrative controls to be adequate to ensure that corrective actions are uniform and thorough.

Operating Experience

The CAP provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Review of the operating experience sections for the other AMPs provides numerous examples of the CAP being used to address and correct age-related conditions adverse to quality.

The results of CAP audits since 1995 were reviewed. The review determined that findings from the CAP audits have resulted in enhancements to the CAP.

On the basis of its review of operating experience discussed in the LRA, the staff finds that the CAP has been effective in correcting conditions adverse to quality. Further, the staff finds that the applicant's evaluation process for the CAP has resulted in improvements to the program.

On the basis of the information provided in the LRA, as supplemented by the information in Section B to the applicant's October 10, 2000, RAI response, with respect to the applicability of Appendix B to 10 CFR Part 50 requirements to the corrective actions, confirmation process, and administrative control attributes for the aging management programs at Plant Hatch, the staff has determined that there is reasonable assurance that the applicant's QA program will adequately address those attributes during the period of extended operation. Therefore, RAI 3.1.8-2 is closed.

In addition, on the basis of the information provided in the LRA, as supplemented by the information in Section B to the applicant's October 10, 2000, submittal, with respect to the remaining program attributes, the staff has determined that there is reasonable assurance that the applicant's QA program will adequately address those attributes during the period of extended operation.

3.1.8.4 Conclusion

The staff has reviewed the information presented in Section A.1.8, of the LRA, "Corrective Actions Program" and Section B.1.8, of the applicant's October 10, 2000 submittal, "Corrective Actions Program." On the basis of this review, the staff concludes that the Plant Hatch FSAR Supplement containing the corrective actions, confirmation process, and administrative control attributes described in Section B to the applicant's RAI response dated October 10, 2000, and which are governed by the Plant Hatch QA program, will provide reasonable assurance that these aging management program attributes will be implemented in an acceptable manner during the period of extended operation. In addition, the staff concludes that the remaining program attributes provide reasonable assurance that the corrective actions program will manage the aging effects associated with components within the scope of license renewal and subject to an AMR.

3.1.9 Inservice Inspection Program

3.1.9.1 Introduction

The applicant described its ISI program AMP in LRA Sections A.1.9 and Section B.1.9 of the applicant's October 10, 2000 submittal. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that this program will manage the effects of aging on structures and components such that the associated systems will perform their intended function(s), consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The ISI Program is a condition monitoring program that provides for the implementation of ASME Code, Section XI, in accordance with the provisions of 10 CFR 50.55a. The ISI Program also includes augmented examinations required to satisfy commitments made by the applicant (e.g., GL 88-01, NUREG-0619). The 10-year examination plan provides a systematic guide for performing nondestructive examination of passive components within the scope of license renewal.

Plant Hatch has two units with different dates for construction permits and operating licenses. However, Unit 2's first 10-year interval was completed early (1986), so both units would be committed to the same version of ASME Section XI. Accordingly, Plant Hatch is currently in the third 10-year interval. The period of extended operation will include the fifth and sixth ISI intervals.

3.1.9.2 Summary of Technical Information in the Application

The ISI program provides examination methods and acceptance criteria for Class 1, 2, 3 (equivalent), and Class MC pressure boundary components, as well as the associated supports. It also provides for periodic pressure testing of those same components, along with repair, replacement, and modification activities.

Three types of inspection methods are used for inservice examination at Plant Hatch. They are visual inspections, surface inspections, and volumetric inspections. Visual inspections are performed as defined in ASME Code, Section XI, Subsection IWA-2210. Three types of visual examinations are used: VT-1, VT-2, and VT-3. VT-1 inspections are used to determine the condition of the part, component, or surface examined, including cracks, wear, corrosion, and/or physical damage. VT-2 inspections are used to locate evidence of leakage from pressure retaining components during a system pressure test. VT-3 inspections are used to determine the general mechanical and structural condition of components and in associated supports, such as verification of clearances, physical displacements, and loose or missing parts. This includes inspection for debris, corrosion, wear, erosion, and/or loss of integrity at bolted or welded connections.

Surface examinations are performed as defined in Subsection IWA-2220 to determine whether surface cracks or discontinuities exist. Acceptable examination methods include magnetic particle and liquid penetrant methods. Volumetric examinations are performed as defined in IWA-2230 to locate discontinuities throughout the volume of material. These examinations may be conducted from the inside or outside surface of a component. Either radiographic (RT) or UT methods may be used.

ASME Section XI, Subsections IWB, IWC, IWD, and IWE provide examination requirements for ASME Class 1, 2, and 3 (equivalent) and Class MC components, respectively. Subsection IWF addresses component supports, which are treated the same as the Code Class component they support. Code Case N-491 is an acceptable alternative to the tables and scope expansion requirements of ASME Section XI, Subsection IWF.

3.1.9.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the ISI program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The applicant stated that the ISI program contains examination requirements and acceptance criteria for Class 1, 2, and 3 (equivalent), and Class MC pressure boundary components, as well as the associated supports. It also provides for repair, replacement, and modification activities.

The ISI Program is credited for monitoring potential age-related degradation in portions of the following systems:

B11 - Reactor Assembly
B21 - Nuclear Boiler

B31 - Reactor Recirculation
E11 - Residual Heat Removal (RHR) and RHR Service Water
P41 - Plant Service Water
T23 - Primary Containment
T52 - Containment Penetrations

The staff finds the program scope to be acceptable because the scope is comprehensive in that it includes all components for which the ISI program applies.

Preventive or Mitigative Actions

The applicant stated that the ISI program is a condition monitoring program. Therefore, there are no preventive or mitigative attributes associated with this program. The staff agrees that the ISI program does not prevent or mitigate age-related degradation, but rather identifies age-related degradation.

Parameters Inspected or Monitored

The applicant stated that the ISI program utilizes visual, surface, and volumetric examinations of Class 1, 2, and 3, and Class MC pressure boundary components, as well as the associated supports, that would detect potential degradation of their intended functions, as a result of loss of material and cracking, during the period of extended operation. In LRA Section B.1.9 the applicant stated that the ISI program will also be used to detect loss of preload for the applicable in-scope Class 1 systems and components.

The staff finds the parameters to be inspected or monitored to be acceptable.

Detection of Aging Effects

The applicant stated that the ISI Program monitors the aging effects using visual, surface, and volumetric inspection methods. To ensure that the aging effects are identified before there is a loss of intended function, the staff relies on an adequate program scope, appropriate monitoring of parameters, and appropriate frequency interval. Where specific ASME Section XI inspection requirements are credited to manage the effects of aging in the LRA, the extent and frequency of examinations are predicated on the tables in Article 2500 of ASME Section XI, Subsections IWB, IWC, IWD, IWE, and IWF. The staff finds that the ASME Code requirements used to detect aging effects are adequate.

Monitoring and Trending

The applicant stated that deficiencies discovered during the performance of the program activities are documented in accordance with the procedures implementing the Plant Hatch ISI program. Deficiencies discovered through the ISI program are monitored in accordance with ASME Code requirements. Deficiencies requiring repair or replacement are entered into the plant corrective action program. The staff finds this process adequate to effectively monitor and trend age-related degradation.

Acceptance Criteria

The applicant stated that, for the third 10-year inspection interval, Plant Hatch uses the 1989 Edition of the ASME Code, Section XI, for Class 1, 2, and 3 systems and components. Components not meeting the acceptance criteria defined in ASME Section XI, Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 are evaluated, repaired, or replaced before returning to service. In 1996, Plant Hatch submitted a request for relief from meeting the requirements of the ASME Code for Class MC component repairs and replacement until September 9, 1997. The NRC approved the request for relief in May 1997. Accordingly, repairs, replacements, or modifications for Class MC components that occurred after September 9, 1997, have been performed in accordance with the requirements of the ASME Code, Section XI, 1992 Edition with 1992 Addenda. The staff finds that the acceptance criteria used by the applicant is acceptable.

Operating Experience

The applicant stated that the Plant Hatch ISI program is founded on the requirements of the ASME Code. The ASME Code development process includes extensive review and approval by industry experts, thereby assuring that any significant industry data has been considered in the development of the ASME Code, which forms the basis for the Plant Hatch ISI program. In addition, the Commission's process of reviewing Editions and Addenda of the ASME Code and incorporating them into 10 CFR 50.55a provides additional assurance that all significant issues have been considered. The applicant stated that several deficiencies have been identified on the in-scope components and systems. For those identified as age-related, the applicant's corrective actions program was used to address the concerns, in accordance with Plant Hatch's implementation of ASME Code, Section XI, within the ISI program. The corrective actions program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences. The staff finds that the acceptance criteria used by the applicant for this AMP is appropriate.

3.1.9.4 Conclusions

The staff has reviewed the information in LRA Sections A.1.9, "Inservice Inspection Program," and Section B.1.9 of the applicant's October 10, 200 submittal. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects managed by the ISI program will be adequately managed so that there is reasonable assurance that the systems covered by this inspection program 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).

3.1.10 Overhead Crane and Refueling Platform Inspections

3.1.10.1 Introduction

The applicant described its overhead crane and refueling platform inspections in LRA Sections A.1.10 and B.1.10. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging managed by the overhead crane and refueling platform inspections will be adequately managed so that there is reasonable assurance that the systems covered by this inspection program 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).

3.1.10.2 Summary of Technical Information in the Application

In Section A.1.10 of the LRA and Section B.1.10 of the applicant's submittal dated October 10, 2000, the applicant describes an existing aging management program, the overhead crane and refueling platform inspection program, that provides for periodic visual inspections to monitor the condition of the passive structural elements of the crane and refueling platform with respect to their structural integrity. The applicant identified loss of material as a result of corrosion as the aging effect requiring management by this program. The affected mechanical systems include the refueling platform equipment assembly and the reactor building crane. The applicant lists the specific systems, structures, and components in LRA Section 3.2. These two mechanical systems are fabricated from either carbon steel or aluminum. In addition to the overhead crane and refueling platform inspection program, the protective coatings program, which is described in LRA Section A.2.3, is also used to manage the loss of material aging effect for these two mechanical systems.

The applicant states that the overhead crane and refueling platform inspection activities satisfy the requirements of the Unit 1 Technical Requirements Manual, which has provisions for surveillance testing of the 5-ton hoist and the crane /hoist used for handling fuel assemblies or control rods. The overhead crane and refueling platform hoist, rigging, slings and lifting devices are visually inspected to detect evidence of loss of material. The overhead crane and refueling platform inspection program also includes a number of other inspection activities that are not credited for license renewal aging management, such as a pre-operational static inspection, pre-operational dynamic inspection, operational inspection, and maintenance inspection.

3.1.10.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the overhead crane and refueling platform inspections program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

In Section B.1.10 of its October 10, 2000 submittal, the applicant stated that the reactor building overhead crane and refueling platform are generally considered to be active components; however, the components that are responsible for the structural integrity of the crane and refueling platform are considered to be passive, and are thus within the scope of license renewal. The passive structural load-bearing components include the crane girder, rails, and bolts. Regarding the inspection scope, the applicant stated, in response to RAI 3.1.10-2, that the active moving sub-components of the overhead crane and refueling platform, such as the wire rope, drums, and other associated parts, are not within the scope of license renewal. Therefore, aging effects such as cracking of the wire rope and mechanical degradation/distortion attributable to fatigue were not considered for the overhead crane and refueling platform inspection program. In response to RAI 3.1.10-5, the applicant stated that galvanic corrosion between the aluminum rivets and structural steel of the refueling equipment assembly is not an aging effect requiring management because the aluminum surfaces exposed to air will develop a thin oxide coating, and no electrolyte is present to initiate or sustain a galvanic reaction. The staff finds that the scope of the overhead crane and refueling platform inspections program is acceptable since it includes a visual inspection of all of the passive components that are responsible for the structural integrity of the overhead crane and refueling platform.

Preventive and Mitigative Actions

There are no preventive or mitigative actions taken as part of this program, and the staff did not identify the need for such actions.

Parameters Inspected or Monitored

The contacting surfaces of the passive structural load bearing components of the overhead crane and refueling platform such as the crane girder, rails, and bolts, are periodically inspected in accordance with plant procedures. The staff finds that visual inspections will be adequate for identifying loss of material from these surfaces during the period of extended operation.

Detection of Aging effects

With respect to the frequency interval of inspections, the applicant stated in Section B.1.10 of its October 10, 2000, submittal that general visual inspections are performed monthly and that the overhead cranes are inspected daily when in use. The staff finds that the applicant's operating experience to date supports the continuation of this inspection frequency interval and will provide reasonable assurance that the loss of material aging effect will be detected before there is a loss of intended function.

Monitoring and Trending

The applicant stated that the results of the system inspections and tests are documented in accordance with procedural requirements. In addition the corrective actions program is used to monitor the component deficiencies and to implement timely corrective actions. The staff finds that these monitoring activities are adequate to ensure that corrective actions will be taken before exceeding the acceptance criteria.

Acceptance Criteria

The applicant states that the acceptance criteria for the overhead crane and refueling platform inspection program is that, "bridges, bridge rails, trolley, and trolley rails must be straight, and without evidence of physical damage such as cracking." The staff finds that the acceptance criteria specified above are adequate to ensure that the system intended function(s) are maintained under all CLB design conditions during the period of extended operation.

Operating Experience

The overhead crane and refueling platform inspection program is an existing program; however, the applicant did not provide a description of the program inspection findings. In response to RAI 3.1.10-6, the applicant stated that a review of the "plant deficiency cards" from the past 5 years did not reveal any loss of material from the in-scope components of the overhead crane or the refueling platform. The staff finds that the applicant's operating experience has demonstrated that the overhead crane and refueling platform inspection program has effectively maintained the structural integrity of the overhead crane and refueling platform, and the effects of aging will be adequately managed so that the system intended function will be maintained during the period of extended operation.

3.1.10.4 Conclusions

The staff has reviewed the information in LRA Sections A.1.10, "Overhead Crane And Refueling Platform Inspections," and Section B.1.10 of the applicant's October 10, 2000 submittal. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects managed by the overhead crane and refueling platform inspection program will be adequately managed so that there is reasonable assurance that the systems covered by this inspection program 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).

3.1.11 Torque Activities

3.1.11.1 Introduction

The applicant described its torque activities AMP in LRA Sections A.1.11, C.2.1.1.6, and C.2.2.10 and Section B.1.11 of the applicant's October 10, 2000 submittal. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging managed by the torque activities will be adequately managed so that the systems covered by this activity 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).

3.1.11.2 Summary of Technical Information in the Application.

Torque activities are intended to mitigate loss of preload through use of proper torque techniques at Plant Hatch. Plant procedures provide specific instructions for maximizing the effectiveness of torque activities.

Hardened steel washers may be used in conjunction with joint bolting, since they allow more of the applied torque to be translated to bolt stress, which provides the preload necessary for a tightly sealed joint. In joints subject to thermal or process load cycling, Belleville washers may be used to provide better response to the changing conditions caused by cycling.

Bolting threads and load bearing faces are lubricated with an approved thread lubricant immediately before assembly to allow the maximum torque to be translated to bolt stress. Leveling passes are performed using a calibrated torquing tool and continue until there is no rotational movement of the fasteners at the final torque value.

For any joint considered at high risk for leakage, as demonstrated by past performance or suggested by the judgment of the responsible supervision, leveling passes may be repeated at the final torque value after 24 hours. This may be done to compensate for gasket relaxation (creep) before putting the joint into service.

3.1.11.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the torque activities AMP to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The application stated that the plant commodity group in the scope for torque activities is Class 1 pressure boundary bolting and Non-Class 1 pressure boundary bolting. Class 1 pressure boundary bolting is fabricated from low alloy steel. The non-Class 1 pressure boundary bolting is fabricated to the requirements of ASTM A-307 (Grade B), ASME SA-194 (Grade 2H), and ASME SA-193 (Grade B7). Bolting that is heat treated to a high hardness condition and exposed to a humid environment within containment could be susceptible to SCC. In response to RAI 3.4-1, the applicant did not state if the yield strength for ASME SA-193 (Grade B7) or any other bolts are limited to less than 150 ksi to avoid the possibility of stress corrosion cracking. (See RICSIL No. 055, February 1, 1991, "RPV Head Stud Cracking."). In Open Item 3.1.11-1, the staff requested that the applicant provide this information. By letter dated June 5, 2001, the applicant stated that these bolts were procured with a minimum yield strength of 105 ksi, with no upper limit stated. However, the applicant also stated that it has not experienced problems with these bolts and could not identify any problems during a survey of industry experience. On the basis that the applicant's operating experience has not shown that these bolts have experienced SCC, the staff finds the applicant's response adequate and considers Open Item 3.1.11-1 closed.

The systems where torque activities are applied that contain Class 1 pressure boundary bolting are:

B21 - Nuclear Boiler
B31 - Reactor Recirculation

The systems where torque activities are applied that contain Non-Class 1 pressure boundary bolting are:

B21 – Nuclear Boiler
C11 – Control Rod Drive
E11 – Residual Heat Removal
E21 – Core Spray
E41 – High Pressure Coolant Injection
E51 – Reactor Core Isolation Cooling
N61 – Main Condenser
P41 – Plant Service Water
P42 – Reactor Building Closed Cooling Water
P52 – Instrument Air
P64 – Primary Containment Chill Water
P70 – Drywell Pneumatic
T23 – Primary Containment
T41 – Reactor Building HVAC
T48 – Primary Containment Purge and Inerting
T49 – Post-LOCA Hydrogen Removal
W33 – Traveling Water Screens, Trash Racks
X41 – Outside Structures HVAC
X43 – Fire Protection
Y52 – Fuel Oil

Z41 – Control Room HVAC

The staff agrees that it is appropriate to include the systems listed above within the scope of torque activities.

Preventive or Mitigative Actions

The applicant states for both Class 1 and Non-Class 1 bolting, the torque activities are designed to mitigate age-related degradation by controlling preload within bolted connections. The staff agrees that torque activities are preventive actions and are appropriate for the systems listed.

Parameters Inspected or Monitored

The applicant states that the torque activities sufficiently mitigate loss of preload such that this attribute of aging management is not required. The staff agrees that this attribute is not needed.

Detection of Aging Effects

The applicant states that the torque activities sufficiently mitigate loss of preload such that this attribute of aging management is not required. The staff agrees that this attribute is not needed.

Monitoring and Trending

The applicant states that the torque activities sufficiently mitigate loss of preload such that this attribute of aging management is not required. The staff agrees that monitoring and trending is not required for torque activities.

Acceptance Criteria

The torque activities provide acceptance criteria for loss of preload by specifying torque values, bolt sequence, number of passes, and thread engagement. The staff agrees that the activities specified provide an adequate acceptance criteria.

Operating Experience

The application states that the corrective actions program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences. The staff finds this acceptable.

3.1.11.4 Conclusions

The staff has reviewed the information in LRA Sections A.1.11, "Torque Activities," C.2.1.1.6, and C.2.2.10, and Section B.1.11 of the applicant's October 10, 2000 submittal. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects managed by the torque activities will be adequately managed so that there is reasonable assurance that the systems covered by this activity 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).

3.1.12 Component Cyclic and Transient Limit Program

3.1.12.1 Introduction

The applicant described its component cyclic and transient limit program (CCTLP) in LRA Sections A.1.12 and Section B.1.12. The staff reviewed these sections to determine whether the applicant has demonstrated that the effects of aging managed by the CCTLP will be adequately managed so that the systems covered by this program 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).

3.1.12.2 Summary of Technical Information in the Application

In LRA Section A.1.12 and Section B.1.12, the applicant described an existing aging management program, the component cyclic and transient limit program, that "is designed to track cyclic and transient occurrences to ensure that reactor coolant pressure boundary components and the torus will remain within ASME Code Section III fatigue limits, including the effects of a reactor water environment." The monitored locations include four limiting high-stress RPV boundary components on each unit, limiting locations for the torus on each unit, and eight locations within the Class 1 boundary. These monitoring locations are discussed in greater detail in Section 4.2 of this SER. The program requires that the cumulative usage factor (CUF) for each limiting component for each unit be updated at least once per operating cycle. The program also requires that corrective actions be initiated if the CUF is projected to exceed the Code limit during the 60-year plant life. The applicant identified this AMP as the method it uses to manage the Class 1 fatigue analyses for the period of extended operation in accordance with 54.21(c)(1)(iii).

A criterion of CUF> 0.1 was also used as the basis for postulating pipe breaks at Plant Hatch. The applicant also identified this AMP as the method it uses to manage pipe break postulation based on CUF for the period of extended operation in accordance with 54.21(c)(1)(iii).

3.1.12.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the component cyclic and transient limit program to ensure that the reactor coolant pressure boundary components and the torus will remain within the acceptance criteria discussed above for the period of extended operation.

Program Scope

The scope of the program includes the RPV, the torus and all Class 1 piping. The program monitors locations of high fatigue usage determined by the applicant's review of the design calculations. The staff identified Open Item 4.1.3-1 in Section 4.1 of this SER regarding the scope of the applicant's fatigue TLAA evaluation. Specifically, the staff requested that the applicant explain how the fatigue analysis of the vessel internals was found to be acceptable for the 60-year period. The staff also requested that the applicant identify any other components of the reactor coolant pressure boundary that had fatigue analyses and explain how these analyses were found acceptable for the 60-year period. As discussed in Section 4.1 of this SER, the applicant performed an evaluation of the vessel internals to demonstrate that the allowable CUF will not be exceeded during the period of extended operation. Additionally, the applicant did not identify any other components of the reactor coolant pressure boundary with fatigue analysis. On the basis of the applicant's response to Open Item 4.1.3-1, the staff finds the scope of the CCTLP adequate to address fatigue reactor coolant pressure boundary components.

As part of the resolution of Open Item 4.1.3-1, the applicant proposed to monitor three locations for comparison to the pipe break postulation criteria of CUF > 0.1. These are locations where pipe breaks were not postulated in the initial design, but locations where the pipe break postulation criterion could be exceeded during the period of extended operation. The staff finds the applicant's proposal to monitor sample bounding locations an adequate method to address pipe break postulation criterion based on fatigue usage.

Preventive and Mitigative Actions

There are no preventive or mitigative actions taken as part of this program, and the staff did not identify the need for such actions.

Parameters Inspected or Monitored

The monitored locations are discussed in Sections 4.1 and 4.2 of this SER. The staff finds that monitoring these selected high fatigue usage locations provides an acceptable method to monitor the fatigue usage associated with design transients for the RPV, torus, and Class 1 piping.

Detection of Aging Effects

The program monitors design transients used in the fatigue analysis of components and the information is used to update the fatigue calculation. The staff identified Open Item 4.2.3-1 in Section 4.2.3 of this SER regarding the applicant's evaluation of environmental fatigue concerns. Specifically, the staff disagreed with the applicant's determination that environmental fatigue concerns regarding the six locations identified in NUREG/CR-6260 have been adequately addressed at Plant Hatch. In response to Open Item 4.2.3-1, the applicant proposed to modify the program and apply overall multipliers on the CUFs that account for environmental effects at the six locations identified in NUREG/CR-6260. The staff finds that the aging effects will be adequately monitored by this modified program.

Monitoring and Trending

According to the applicant, the projected 60-year CUF is updated at least once per operating cycle. The applicant indicates that if the fatigue usage factor is projected to exceed the acceptance criteria, a condition report is initiated to determine, and take, appropriate corrective action. The applicant lists the following potential corrective actions:

- trend the 60-year CUF projection and verify that CUF will not exceed 1.0 during the current operating cycle
- refine the fatigue analysis and modify the monitoring formula
- use fracture mechanics analysis to determine a critical flaw size and establish an appropriate inspection schedule

- perform corrective maintenance
- replace the component

The staff considers refinement of the fatigue analysis, repair, or replacement of the component acceptable corrective actions. The use of a fracture mechanics analysis for cases where the CUF is projected to exceed 1.0 would require staff review and approval on a case-by-case basis.

Acceptance Criteria

As stated above, the applicant's acceptance criteria is the condition that the CUF for the monitored locations not exceed 1.0. The applicant will also monitor potential pipe break postulation locations to assure that the CUF does not exceed 0.1. The staff considers this criteria acceptable.

Operating Experience

The applicant's program involves tracking transients at locations of high calculated fatigue usage to manage the fatigue TLAAs. The applicant indicated that it has modified its counting procedure to reflect operating experience, and has added additional monitoring points to the program. Thus, the staff concludes that the applicant considered operating experience in the program development.

3.1.12.4 Conclusions

The staff has reviewed the information in LRA Section A.1.12, "Component Cyclic and Transient Limit Program," and Section B.1.12 of the applicant's October 10, 2000 submittal. The applicant references the component cyclic and transient limit program in its discussion of the fatigue TLAAs as a method to manage the fatigue usage of selected components. The staff identified open items regarding the applicant's TLAA evaluation in Sections 4.1 and 4.2 of this SER. The resolutions of those open items are also discussed in Sections 4.1 and 4.2 of this SER. The staff considers the applicant's program, which monitors the number of plant transients that were assumed in the fatigue design of selected high-fatigue-usage components, including pipe break postulation, to be an acceptable method to manage the fatigue usage of the RPV, torus structure, and RCS piping.

The staff concludes that the component cyclic and transient limit program will adequately manage thermal fatigue of RCS components and torus structure components for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.13 Plant Service Water and RHR Service Water Inspection Program

3.1.13.1 Introduction

The applicant described the PSW and RHRSW inspection program in LRA Section A.1.13. The applicant supplemented the description of this AMP in Section B.1.13 of its October 10, 2000 submittal. The applicant credits this inspection program with managing, in part, aging effects for a variety of carbon steel, stainless steel, copper alloy, and gray cast iron components that are exposed to a raw water or buried environment. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the PSW and RHRSW inspection program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.13.2 Summary of Technical Information in the Application

In Sections A.3.1.13 and Section B.1.13 of the applicant's October 10, 2000 submittal, the applicant describes the PSW and RHRSW inspection program, that manages, in part, aging effects for various structures and components exposed to a raw water or buried environment. The affected systems include the RHR system, PSW system, and traveling water screens/trash racks system. The applicant lists the specific system structures and components in Tables 3.2.3-2, 3.2.4-7, and 3.2.4-16 of the LRA. These structures and components are fabricated from either carbon steel, stainless steel, copper alloy, or gray cast iron.

As discussed in Sections C.1.2.4 and C.1.2.10 of the LRA, loss of material is an applicable aging effect that may affect carbon steel, stainless steel, copper alloy, or gray cast iron components exposed to raw water or buried environments through several corrosion mechanisms, including general corrosion, galvanic corrosion, crevice corrosion, pitting, MIC, selective leaching, and erosion corrosion. The applicant also considered fouling to be an applicable aging effect. Fouling is not a material degradation phenomenon but may increase corrosion rates within raw water system components for a limited set of component geometries. Additionally, fouling may result in a loss of intended function (i.e., decreased flow or pressure) due to the buildup of material on raw water system component internal surfaces. Although the applicant also identified wear and cracking due to vibration fatigue as applicable aging mechanisms, these mechanisms are specific to the RHR heat exchanger which has its own AMP (the RHR heat exchanger augmented inspection and testing program), and thus are not addressed by the PSW and RHRSW inspection program.

Plant Hatch has two sources of raw water, river and well water. River water from the Altamaha River is supplied and rough screened at the intake structure. The applicant assumes that some debris, silt, and macroorganisms may be introduced into the PSW and RHRSW systems. This is the type of raw water relevant to this inspection program. The applicant relies on a combination of AMPs to mitigate and detect aging effects for the various structures and components exposed to the river water environment. These complementary programs include the PSW and RHRSW chemistry control program, the PSW and RHRSW inspection program, galvanic susceptibility inspections, and the RHR heat exchanger augmented inspection and testing program. This section of the SER describes and evaluates the applicant's plant service water and RHR service water inspection program.

3.1.13.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the PSW and RHRSW inspection program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The applicant stated in Section B.1.13 of the applicant's October 10, 200 submittal, that the scope of this program included structures and components within the RHR system, RHRSW system, and traveling water screens/trash rack system, as specified in Tables 3.2.3-2, 3.2.4-7, and 3.2.4-16 of the LRA. The inspection scope consists of a representative sample of the most susceptible locations for corrosion or fouling. Locations susceptible to corrosion include infrequently used piping (stagnant water), submerged piping, piping with low fluid velocity, piping with high fluid velocity (erosion), small diameter piping, backing rings, socket welds, and heat affected zone of welds. Locations susceptible to fouling include those also susceptible to corrosion, horizontal runs of piping at the bottom of vertical runs, intermittently used piping, or low point drains. To address selective leaching, the applicant will include one PSW component fabricated from brass and one component fabricated from gray cast iron.

In Section C.2.4.3 of the LRA, the applicant credits the PSW and RHRSW inspection program with managing the aging effects of RHR and PSW components exposed to a buried environment. The protective coatings program includes provisions for cleaning, priming, coating, and wrapping underground pipelines whenever underground sections of pipe are uncovered. Pipelines are wrapped with coal tar enamel wrapping. However, this aspect of the program is not discussed in Section A.1.13 of the LRA or Section B.1.13 of the applicant's October 10, 2000 submittal. The staff requested that the applicant enhance its description of the PSW and RHRSW inspection program to clearly state that the scope of the program includes this particular aspect for managing aging effects associated with a buried environment, consistent with the discussion in Section C.2.4.3 of the LRA. This was identified as part of Open Item 3.1.13-1 [3.1.13-1(a)].

The applicant responded to this open item by letter dated June 5, 2001. The applicant indicated that the PSW and RHRSW inspection program does not directly include provisions for cleaning, priming, coating and wrapping underground pipelines. The protective coatings program addresses these activities. However, the site procedure for buried pipelines coating maintenance does specifically invoke the program inspection requirements whenever maintenance is performed on the components in those systems. There is, therefore, certain linkage between these two programs and the applicant reflected it in the LRA. In order to clarify this issue, the applicant will modify the LRA. It will remove the PSW and RHRSW inspection program from Section C.2.4.3. In addition, the applicant will modify Section B.3.5 of the LRA by removing information related to the external surfaces of buried components. A special instruction has been placed in the site procedure used to manage excavation activities to assure that buried commodities are examined by protective coatings personnel. The staff finds that with these modifications introduced in the LRA, the scope of the PSW and RHRSW inspection program with regard to inspection of the underground pipelines is well defined. The staff considers Open Item 3.1.13-1(a) closed.

In Table 3.2.3-2 of the LRA, the RHR heat exchanger augmented inspection and testing program is credited with managing, in part, aging effects for various heat exchanger components, including the tubes, tubesheet, and shell. However, the staff noted that the description of the PSW and RHRSW inspection program contained in Section B.1.13 of the applicant's October 10, 2000 submittal included several references to inspections of heat exchanger components. The staff requested that the applicant clarify the scope of the PSW and RHRSW inspection program relative to managing aging effects for the various heat exchanger components listed in Table 3.2.3-2 of the LRA. This was identified as part of Open Item 3.1.13-1 (Open Item 3.1.13-1(b)).

The applicant responded to this open item by letter dated June 5, 2001. The applicant stated that managing aging effects for various heat exchanger components, including the tubes, tubesheet, and shell in the RHR system is performed by the RHR heat exchanger augmented inspection and testing program. As indicated in Section C.2.2.11 of the LRA, the PSW and RHRSW inspection program plays only a subordinate role, limited to visual inspection of the surfaces of the heat exchanger channel and shell sides. The reason that inspection of the heat exchanger components is referenced in Section B.1.13 of the LRA is to show the linkage that exists between these two programs. On the basis of this information, the staff concludes that the applicant has clarified the scope of the PSW and RHRSW inspection program regarding management of aging effects in the RHR heat exchanger. The staff considers Open Item 3.1.13-1(b) closed.

The staff conducted a scoping inspection in the offices of SNC from September 11, 2000 through September 15, 2000. The results of the inspection are documented in Inspection Report 50-321/00-09, 50-366/00-09. During the inspection, the inspectors identified a guard pipe associated with Division I PSW piping in the diesel generator building. This guard pipe had not been considered for scoping and screening in the LRA. In response to this inspection finding, the applicant evaluated the guard pipe and concluded that it did not perform an intended function, and therefore was not within the scope of license renewal. The staff agreed with this conclusion. The staff's review of the applicant's evaluation of the guard pipe can be found in Section 2.3.4 of this SER. The internal surface of the PSW piping is exposed to raw water, and thus the aging effects and AMPs are consistent with other piping sections in this system. However, the length of the PSW piping surrounded by the guard pipe is sealed, that is, a plate is welded to the PSW pipe and to the guard pipe at both ends. Thus, the external surface of this section of PSW piping is not accessible for inspection. The applicant plans to perform a one-time inspection to assess the material condition of the external surfaces of this piping section. The staff requested that the applicant provide appropriate information about this one-time inspection, or a comparable engineering evaluation, prior to the end of the current term. This was identified as part of Open Item 3.1.13-1 (3.1.13-1(c)).

The applicant responded to this open item by letter dated June 5, 2001. The applicant provided additional information related to the one-time inspection of that portion of the PSW piping that is surrounded by a guard pipe. The applicant states that Plant Hatch Engineering Support is responsible for determining the suitable method or methods for conducting an inspection. Plans have been made to inspect the portion of the external surface of the PSW piping that is surrounded by the guard pipe during the 1B EDG outage scheduled for February 2002. Currently, the plan is to cut a window in the guard pipe for a visual, boroscope, or other suitable examination to determine the condition of the external surface of the PSW pipe. The results will be documented and evaluated, with additional actions taken if needed. The staff has reviewed the information discussed in the applicant's open item response and, on the basis of this information, concludes that the approach for determining the current state of the guarded external surface of the PSW piping is appropriate and acceptable. Open Item 3.1.13-1(c) is closed.

The staff finds that the scope of the PSW and RHRSW inspection program is acceptable because it includes all the components in the RHR system, PSW system, and traveling water screens/trash rack system that are exposed to a raw water environment. In addition, the inspection scope includes a representative inspection sample set that is conservatively biased to those locations considered to be most susceptible to corrosion or fouling.

Preventive or Mitigative Actions

One aspect of the PSW and RHRSW inspection program is mitigative in nature. The program requires the regular, periodic visual inspections of the intake structure pump suction pit. Any accumulations of biological fouling organisms, sediment, or corrosion products found during the inspection will be removed to prevent their entry into the system. The staff agrees this action will help to mitigative the impact such accumulations have on corrosion and fouling.

Parameters Monitored or Inspected

The applicant applies qualified inspection techniques, including visual and volumetric (radiographic and ultrasonic) inspections of structures and components to detect corrosion-related aging effects. The applicant also performs flow testing and visual or volumetric inspections to detect fouling. Lastly, the applicant will perform hardness testing or a metallurgical analysis on brass or gray cast iron components to detect selective leaching. The staff finds the inspections and flow rate and hardness testing/metallurgical analysis to be acceptable because the methods are consistent with current industry practice and found to be effective in detecting these aging effects.

Detection of Aging Effects

To ensure that aging effects are identified before there is a loss of intended function, the staff relies on an adequate program scope, appropriate monitoring of parameters, and appropriate frequency interval. The program scope and parameter monitoring are discussed above. With respect to frequency, the applicant stated that the visual inspection of the intake structure pump suction pit is performed every twelve months. The hardness testing of the brass or gray cast iron components will be a one-time inspection, unless results indicate a need for future or expanded inspections. Inspection frequencies for all other structures and components within the scope of this program are based on past inspection results, to ensure that minimum wall thickness values or flow areas are not reduced to unacceptable levels. The staff finds this approach of basing inspection frequency on inspection results to be reasonable and therefore acceptable.

Monitoring and Trending

As discussed above, the applicant stated that inspection results are trended to determine the scope and frequency of subsequent inspections. This approach is reasonable and consistent with industry practice and staff expectations and therefore, is acceptable to the staff.

Acceptance Criteria

For wall loss evaluations, minimum wall thickness is calculated in accordance with the piping design code, piping stress requirements, and piping specification drawings. Flow rate testing for the evaluation of pipe blockage is based upon functional performance requirements for a particular component under normal and accident conditions. Hardness testing is based on the component's material specifications (e.g., ASME, ASTM, etc.). These criteria are reasonable and consistent with industry practice and staff expectations and therefore, are acceptable to the staff.

Operating Experience

The applicant stated that review of Plant Hatch operating experience over the past 5 years has indicated some aging-related problems in the PSW and RHRSW systems. The problems consisted of loss of material, cracking, and loss of heat exchanger performance. The applicant addresses these deficiencies through its corrective actions program. The applicant stated that significant improvements have been made to the plant service water and RHR service water inspection program. For example, the frequency of inspections has been increased and additional nondestructive examinations introduced. In some cases replacement components were made of improved materials. The staff concludes that the applicant has appropriately incorporated operating experience into the PSW and RHRSW inspection program. In addition, the applicant in its January 31, 2001 letter discusses hardness testing for selective leaching of gray cast iron and brass components and in LRA Section B.2.3 discusses operating experience relative to corrosion of buried piping. The staff finds that this operating experience supports the attributes of this program specific to selective leaching and buried piping.

3.1.13.4 Conclusions

The staff has reviewed the information in LRA Section A.1.13 and Section B.1.13 of the applicant's October 10, 2000 submittal. On the basis of this review, pending completion of the license condition, the staff concludes that the applicant has demonstrated that the PSW and RHRSW inspection program will adequately manage, in conjunction with other AMPs, aging effects associated with the raw water or buried environment for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.14 Primary Containment Leakage Rate Testing Program

3.1.14.1 Introduction

The applicant described its primary containment leakage rate testing program in LRA Section A.1.14. The applicant supplemented the description of this AMP in Section B.1.14 of its October 10, 2000 submittal. The applicant credits this inspection program with ensuring the structural integrity of primary containment through visual inspection and performance testing activities. Loss of material is the aging effect monitored by this program. The staff reviewed the application to determine whether the applicant has demonstrated that the primary containment leakage rate testing program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.14.2 Summary of Technical Information in the Application

In LRA Section A.1.14 and Section B.1.14 its October 10, 2000 submittal, the applicant describes an existing aging management program, the primary containment leakage rate testing program, that ensures the structural integrity of primary containment. The program applies to steel primary containments, containment penetrations, and containment internal structures that perform a structural or pressure retaining function. It also includes the steel and nonferrous components of the containment airlocks, equipment hatches, and control rod drive removal hatches. The applicant lists the specific system, structures, and components in LRA Section 3.3.

3.1.14.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the primary containment leakage rate testing program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

In LRA Section A.1.14, the applicant states that the primary containment leakage rate testing program complies with all 10 CFR Part 50 Appendix J, Option B leakage rate testing requirements for systems, structures, and components within the scope of license renewal. The applicant also states that the primary containment leakage rate testing program involves Type A, B, and C pressure testing and that a general visual inspection of the accessible interior and exterior surfaces of the drywell and torus are performed before conducting a Type A test. Given the staff's review of the above information, staff RAI 3.6-1 asked the applicant to provide a discussion of the key elements of the primary containment leakage rate testing program and specifically describe the implementation of regulatory positions C1 through C4 of Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program." The RAI also asked the applicant to provide the bases for any exceptions to these regulatory positions.

In response to RAI 3.6-1, the applicant stated that the program provides for the implementation of all 10 CFR Part 50 Appendix J, Option B leakage rate testing requirements, as required by the Unit 1 and Unit 2 Technical Specifications. The applicant further stated that the program was developed through the use of 10 CFR Part 50, Appendix J, Option B, Regulatory Guide 1.163, NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," July 26, 1995, and ANSI/ANS 56.8-1994, "American National Standard for Containment System Leakage Testing Requirements." The applicant stated that no exceptions are taken to regulatory positions C.1 through C.4 of RG 1.163. This response is acceptable, and RAI 3.6-1 is closed.

The staff finds that the scope of the program, as described above, is acceptable since it includes Type A, B, and C pressure testing and performance of a general visual inspection of the accessible interior and exterior surfaces of the drywell and torus, which are shown to be a reliable means of ensuring containment functions on the basis of past Plant Hatch operating experience.

Preventive and Mitigative Actions

There are no preventive or mitigative actions taken as part of this program, and the staff did not identify the need for such actions.

Parameters Inspected or Monitored

Among the parameters monitored during the testing and visual inspection are containment pressure, compartment/penetration pressures, overall containment leak rate, localized penetration/compartment closure leak rates, extent of loss of material of inspected surfaces, and localized general degradation of components or coatings.

With respect to the third paragraph of Section A.1.14.1, "Description," on page A.1-17 of the LRA, the applicant stated that "Type A tests are performed in accordance with ANSI/ANS 56.8-1994 and/or Bechtel Topical Report BN-TOP-1"Testing Criteria for Integrated Leakage Rate Testing of Primary Containment Structures for Nuclear Power Plants," November 1972,
and implemented through plant procedures." In RAI 3.6-2, the staff requested that the applicant explain the extent to which Plant Hatch intends to adopt the provisions of the referenced ANSI/ANS standard/report in its implementation of the Type A test program. The applicant was also requested to clarify if the provisions that were adopted from the Bechtel Topical Report BN-TOP-1 are either equivalent to or more stringent than those corresponding provisions of ANSI/ANS 56.8-1994. If not,

the applicant was requested to list those BN-TOP-1 provisions that are less stringent than those of ANSI/ANS 56.8-1994 and reconcile the differences.

The applicant responded that presently Type A integrated leak rate tests (ILRTs) are performed in accordance with Bechtel Topical Report BN-TOP-1. The next ILRT is scheduled to be performed during the Unit 1 spring 2002 outage. Plans are to conduct the ILRT in accordance with BN-TOP-1. The Plant Hatch Unit 1 UFSAR, Section 5.2.5.1, states that "the containment leak test program is performed in the manner described in BN-TOP-1 or ANSI/ANS-56.8-1994." The applicant also stated that Regulatory Guide 1.163 endorses NEI 94-01, which states in Section 1.1, "Generally, an FSAR describes plant testing requirements, including containment testing. In some cases, UFSAR testing requirements differ from those of Appendix J. The alternate performance-based testing requirements contained in Option B of Appendix J will not invalidate such exemptions." The applicant also stated that no formal comparison of ANSI/ANS 56.8-1994 with BN-TOP-1 has been performed at this time. The staff finds this applicant's response adequate and reasonable and considers RAI 3.6-2 closed.

Detection of Aging Effects

Test and inspection frequencies are determined in accordance with plant procedures. An as-found Type B or C test is performed before any maintenance, repair, modification, or adjustment activities that could affect the primary containment boundary's leak-tightness. Since the primary containment leakage rate testing program cannot detect loss of material or cracking before the pressure boundary is compromised, this testing program is used in conjunction with other programs, such as the protective coatings program and the inservice inspection program, to manage the aging effects of the primary containment components and drywell penetrations. The staff finds that the applicant's operating experience to date supports the continuation of these test and inspection frequencies and they will provide reasonable assurance that loss of material, as well as loss of containment leak tightness will be detected before there is a loss of intended function.

Monitoring and Trending

The applicant indicated that the results of tests and inspections are documented in accordance with procedural requirements. In addition, the corrective actions program is used to monitor the deficiencies found and to implement timely corrective actions. The staff finds that these monitoring activities are adequate to ensure that corrective actions will be taken before exceeding the acceptance criteria.

Acceptance Criteria

The applicant stated that criteria are defined for establishing Type A, B, and C test frequencies and administrative leakage limits, on the basis of performance. Type A tests are performed in accordance with ANSI/ANS 56.8-1994 and/or Bechtel Topical Report BN-TOP-1 to demonstrate the integrity of the primary containment pressure vessel. Type A, B, and C test intervals are established in accordance with Regulatory Guide 1.163. Type B and C tests are performed in accordance with ANSI/ANS 56.8-1994, to demonstrate the integrity of individual penetrations and components, with NRC-approved Technical Specification amendments and exemptions. The acceptance criteria for visual inspection are no visual detection of loss of material or cracking. The staff finds that the acceptance criteria specified above are adequate to ensure that the containment intended functions are maintained under all CLB design conditions during the period of extended operation.

Operating Experience

The primary containment leak rate testing program is an existing program. In LRA Section C.2.6.2 the applicant stated that several instances of age related degradation of the containment as a result of minor corrosion were found to date but there were no containment functional failures. These deficiencies were discovered during required visual inspections and pressure testing. The corrective actions program was utilized to correct/repair these deficiencies. The staff finds that the applicant's operating experience has demonstrated that the program has effectively maintained the containment integrity and functionality, and the effects of containment aging will be adequately managed so that intended functions will be maintained during the period of extended operation.

3.1.14.4 Conclusions

The staff has reviewed the information in LRA Sections A.1.14 "Primary Containment Leakage Rate Testing Program," and Section B.1.14 of the applicant's October 10, 2000 submittal. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects managed by the primary containment leakage rate testing program will be adequately managed so that there is reasonable assurance that the structures covered by this inspection program 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).

3.1.15 Boiling Water Reactor Vessel and Internals (BWRVIP) Program

3.1.15.1 Introduction

The applicant described its BWRVIP inspection program in Section A.1.15 of LRA, and supplemented the description of this AMP in Section B.1.15 of its October 10, 2000, submittal. The applicant credits this program with verifying the structural integrity of the RPV internal components to ensure the continued integrity of the load bearing and operating components. The staff reviewed the application to determine whether the applicant has demonstrated that the BWRVIP inspection program will adequately manage aging effects during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.15.2 Summary of Technical Information in the Application

In LRA Section A.1.15 and Section B.1.15 its October 10, 2000, submittal, the applicant describes an existing generic aging management program, the Boiling Water Reactor Vessel and Internals program (BWRVIP), which references the following nine BWRVIP inspection and evaluation (I&E) reports for internals components (these reports apply to both the current term and the extended period of operation):

<u>Reactor Assembly BWRVIP Document Applicability</u>

<u>Component</u>	<u>Reference</u>
Core Spray Piping and Sparger	BWRVIP-18
Top Guide	BWRVIP-26
Standby Liquid Control System/Core Plate dP	BWRVIP-27

Shroud Support	BWRVIP-38
Jet Pump Assemblies	BWRVIP-41
Control Rod Guide Tube	BWRVIP-47
Vessel ID Attachment Weld	BWRVIP-48
Reactor Pressure Vessel	BWRVIP-74
Shroud (including repair hardware)	BWRVIP-76

These nine BWRVIP reports together constitute the BWRVIP AMP. With regard to license renewal, these I&E reports specifically address the subject internals systems and components relative to the requirements of 10 CFR Part 54. The staff's SERs on the BWRVIP I&E reports established the adequacy of the generic BWRVIP reports for renewal by concluding that the license renewal rule provisions have been satisfied, including the identification and assessment of aging effects, the evaluation of the adequacy of the BWRVIP programs with regard to managing the aging effects, and the demonstration that these programs will ensure the functionality of internals during the period of extended operation.

The applicant has evaluated the BWRVIP program for its applicability to the Plant Hatch Units 1 and 2 design, construction, and operating experience, stating that the RPV internals, including the materials of construction, are addressed by the BWRVIP program I&E reports and that the plant operating parameters, including temperature, pressure, and water chemistry, are consistent with those used for the development of the I&E reports. The applicant has determined that the components which require aging management review, in accordance with the license renewal rule, are covered by the referenced BWRVIP program reports, and that the referenced BWRVIP program reports cover all Plant Hatch internals design.

The BWRVIP program provides for periodic inspections to monitor the condition of each internal BWR component that could impact safety, enabling degradation to be detected before the component's function is adversely affected. The applicant stated that the RPV internals requiring aging management within the scope of license renewal are the shroud, shroud supports, core spray piping and spargers, control rod guide tubes, jet pump assemblies, control rod drive housings, and dry tubes. Initially, only the Unit 1 top guide was included within the scope of the AMP. In response to RAI 3.1.15-2, the applicant stated that, given the original design conditions, Unit 2 was shown to not require inspection and, thus, was not referenced in the LRA. However, subsequent to submitting the application, the applicant determined that, because of extended power up-rate, the Unit 2 top guide must also be included. All of the above listed components are included as part of the reactor assembly system.

The reactor internals are examined using a combination of ultrasonic, visual, and surface methods. The methods to be used and the frequency of examination will be as specified in the applicable BWRVIP inspection and evaluation document, unless specific exception has been identified and approved by the staff. Therefore, the applicant has established that the BWRVIP program reports bound the Plant Hatch Units 1 and 2 design and operation.

3.1.15.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration that the BWRVIP will adequately manage the applicable component aging effects so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff evaluated the nine BWRVIP reports that constitute the BWRVIP AMP against the ten aging management program criteria below.

Program Scope

In Section B.1.15 of its October 10, 2000, submittal, the applicant stated that the reactor vessel internals requiring aging management within the scope of the Plant Hatch implementation of the BWRVIP are the shroud and associated shroud repair hardware, shroud supports, core spray piping and spargers, control rod guide tubes, jet pump assemblies, control rod drive housings, and dry tubes. In the original application, only the Unit 1 top guide was included. Subsequent to submitting the application, the applicant determined that, because of extended power up-rate, the Unit 2 top guide must also be included. All of the above listed components are included as part of the reactor assembly system.

The staff finds that the applicant has adequately identified all of the components that are within the program scope.

Preventive or Mitigative Actions

The BWRVIP program is a condition monitoring program which utilizes enhanced visual inspections, as well as volumetric and surface examinations, to detect IGSCC, IASCC, and fatigue within reactor vessel internals such that proper evaluations and corrective actions may be accomplished. Early detection and subsequent evaluation and corrective actions are considered adequate to mitigate degradation of reactor assembly internals before component function is adversely affected.

The staff finds that the BWRVIP program, as used at Plant Hatch, will be adequate to monitor plant conditions to identify conditions adverse to quality in a timely manner.

Parameters Inspected or Monitored

The BWRVIP program reviewed the function of each internal BWR component. For those internals that could impact safety, the BWRVIP program considered the mechanisms that might cause degradation of the internal components and developed an inspection program that would enable degradation to be detected and evaluated before the component function was adversely affected. Details regarding inspection and evaluation are contained within the component-specific BWRVIP inspection and evaluation documents. The staff finds that the applicant has appropriately characterized how the BWRVIP will inspect and monitor components at Plant Hatch to identify and evaluate aging effects.

Detection of Aging Effects

The reactor internals are examined using a combination of ultrasonic, visual, and surface methods. The methods to be used and the frequency of examination will be as specified in the applicable I&E report.

The staff finds the detection methods, as specified, are appropriate to identify and evaluate age-related degradation in internals.

Monitoring and Trending

Monitoring of the detrimental effects of aging within reactor assembly components are specified within the BWRVIP I&E reports. The frequency of examination specified within applicable BWRVIP I&E reports varies for each component or subassembly. The frequency is founded on the component's design, flaw tolerance, susceptibility to degradation, and the method of examination used. In cases where a component may be inspected using either visual or ultrasonic methods, the interval between examinations is shorter when visual methods are used. The Plant Hatch corrective actions program provides for trending of significant indications noted during BWRVIP inspections.

The staff finds the applicant's approach to monitoring and trending aging in components within the scope of the BWRVIP reports appropriate.

Acceptance Criteria

BWRVIP I&E reports provide the basis for Plant Hatch reactor vessel internals inspection requirements, acceptance criteria, and proper corrective actions. The applicant has incorporated these applicable I&E reports into the Plant Hatch license renewal application by specific reference. The staff finds that the acceptance criteria, as provided in the referenced BWRVIP reports, are acceptable.

Operating Experience

The applicant states that the operating experience for the Plant Hatch internals was reviewed. Over time there have been several occurrences of cracking, all of which have been repaired or are currently being monitored in accordance with prescribed procedures and programs. Early in life, IGSCC was detected on the Unit 1 core spray sparger. It was repaired by installation of a mechanical clamp. The sparger has been full-flow tested and the clamp examined afterwards with no evidence of degradation. Multiple indications have been detected over the years on the non-safety-related steam dryers. Some have been repaired while others are monitored. Jet pump inspections have resulted in minor indications associated with setscrew gaps, diffuser-to-adapter welds, riser pipe welds, and tack welds. These are being monitored and reexamined in accordance with the provisions of the BWRVIP. Crack-like indications were also detected in the core shrouds for both units. The applicant conservatively decided to make pre-emptive repairs to eliminate the concern of cracking in shroud circumferential welds. The repair hardware and vertical welds are periodically examined as specified in the BWRVIP.

The applicant has evaluated the BWRVIP AMP for its applicability to the Plant Hatch Units 1 and 2 design, construction and operating experience, including the applicant action items associated with the BWRVIP reports as well as any exceptions to the action items, and has established that the BWRVIP reports bound the Plant Hatch Units 1 and 2 design. The RPV components, including the materials used for construction, are addressed by the BWRVIP inspection and evaluation documents. The plant operating parameters, including temperature, pressure, and water chemistry, are consistent with those used for the development of the inspection and evaluation documents. The staff has reviewed the applicant's evaluation and finds it acceptable.

In summary, the staff concludes that the applicant has determined the following:

- The components which require aging management review in accordance with the rule, are covered by the BWRVIP reports.
- The BWRVIP reports cover all Plant Hatch RPV and internals designs.
- Plant Hatch has met the provisions of the referenced BWRVIP reports, including the associated applicant action items, or has adequately addressed any exceptions to the applicant action items.

3.1.15.4 Conclusions

The staff has reviewed the information in LRA Section A.1.15, "Boiling Water Reactor Vessel and Internals Program," and Section B.1.15 of the applicant's October 10, 2000 submittal, including the bases for the applicant's determination that Plant Hatch meets the provisions of the referenced BWRVIP reports, including the applicant action items, or exceptions thereto, and concludes that implementation of the referenced BWRVIP reports, including the associated applicant action items, and staff-approved exceptions, provides reasonable assurance that the aging effects associated with the components within the scope of the referenced reports will be adequately managed during the period of extended operation to ensure the continued performance of their intended functions during the period of extended operation. On the basis of this review, the staff concludes that the applicant meets the requirements of 10 CFR 54.21(a)(3).

3.1.16 Wetted Cable Activities

3.1.16.1 Introduction

The applicant described its wetted cable activities in LRA Section A.1.16 and Section B.1.16 of the applicant's October 10, 2000 submittal. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on structures and components in systems managed by the wetted cables activities will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.16.2 Summary of Technical Information in the Application

In LRA Section A.1.16 and Section B.1.16 of the applicant's October 10, 2000 submittal, the applicant describes an existing AMP, wetted cables activities, that provides for mitigating activities as well as condition monitoring activities associated with cables exposed to a wetted environment. Plant Hatch wetted cable activities include monitoring for and removing water, along with testing to detect changes in insulation resistance. Several 4kV power cables and transformer feeder cables within the scope of license renewal are routed through the underground duct bank system consisting of outdoor pull boxes containing underground conduits routed between in-scope buildings. Change in insulation resistance is the aging effect mitigated and monitored by the wetted cables activities.

The affected systems include RHR, RHRSW, core spray, and PSW.

3.1.16.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the wetted cable activities program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Water level is measured, recorded, and the pull boxes drained, where these in-scope 4-kV power and transformer cables are routed. Megger and polarization index testing are periodically performed. When new terminations are made, the cables are hipot tested to provide additional assurance that the cable insulation integrity is sound. In addition, the pull boxes are drained quarterly and testing is performed on in-scope 4-kV motor windings and the associated feeder cables during regular motor and pump maintenance tasks.

The wetted cable activities meet the intent of IEEE 43-1974, "Recommended Practice for Testing Insulation Resistance of Rotating Machinery"; and IEEE 95-1977, "Recommended Practice for Insulation Testing of Large AC Rotating Machinery with High Direct Voltage." Pull boxes found to contain water are drained to 1 inch of water or less. Cables and loads must successfully pass megger and polarization index testing. Corrective actions are taken if testing results are unacceptable. Plant-specific operating experience did not identify any in-scope age-related cables failures attributable to moisture intrusion.

The staff finds that the Plant Hatch wetted cable activities manage the effects of cable aging attributable to moisture intrusion so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

3.1.16.4 Conclusions

The staff has reviewed the information in LRA Sections A.1.16, "Wetted Cable Activities," and Section B.1.16 fo the applicant's October 10, 2000 submittal. On the basis of its review, the staff concludes that the applicant has demonstrated that the effects of aging associated with structures and components in systems managed by wetted cable activities will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.17 Reactor Pressure Vessel (RPV) Monitoring Program

3.1.17.1 Introduction

The applicant described its RPV monitoring program in Section A.1.17 of the LRA, and in Section B.1.17 of the applicant's October 10, 2000 submittal. The program consists of a combination of fatigue monitoring, code-required and augmented inspections, and surveillance material testing. The staff has reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed by the RPV monitoring program during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.17.2 Summary of Technical Information in the Application

The RPV Monitoring Program is an existing condition monitoring and surveillance program at Plant Hatch. It is based on detailed evaluation of the Plant Hatch Unit 1 and 2 RPVs. The program is supported by an industry topical report for the license renewal period, BWRVIP-74.

The RPV Monitoring Program covers the reactor vessel beltline shells, feedwater nozzles, core spray nozzles, control rod drive return line nozzle, recirculation inlet and outlet nozzles, jet pump instrumentation nozzles, and penetration seals. The core dP and standby liquid control nozzle, the support skirt and closure studs, the core spray pipe, jet pump riser brace pad, and shroud support welds are also included.

RPV monitoring is accomplished through a combination of fatigue monitoring, code-required and augmented inspections, pressure tests, and surveillance material testing. RPV shell and head aging management is accomplished by performing ultrasonic examinations of the RPV vertical shell welds, periodic pressure tests with visual examination for leakage, and surveillance capsule testing. Plant Hatch uses an NRC-approved technical alternative in lieu of ultrasonic testing of circumferential shell welds. The basis for the alternative is contained in the BWR reactor pressure vessel shell weld inspection recommendations, and associated supplements.

3.1.17.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration that the RPV monitoring program ensures that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

In LRA Section B.1.17 of the October 10, 2000 submittal, the applicant describes the RPV monitoring program for Plant Hatch. The RPV monitoring program employs the programs documented in the following topical reports:

BWRVIP-27, "BWR Standby Liquid Control/Core ΔP Inspection and Flaw Evaluation Guidelines"

BWRVIP-38, "BWR Shroud Support Inspection and Flaw Evaluation Guidelines"

BWRVIP-41, "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines"

BWRVIP-48, "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines"

BWRVIP-74, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines"

The staff's evaluation of these RPV-specific reports, and the other BWRVIP reports referenced by the applicant, are found in Section 3.1.15 of this SER.

LRA Section B.1.17 of the applicant's October 10, 2000 submittal discusses the elements of the RPV monitoring program. The elements discussed are program scope, preventive or mitigation actions, parameters inspected or monitored, method of detecting aging effects, monitoring and trending, and acceptance criteria. The scope of the program includes all components in the reactor assembly system. The description of the other elements of the program consists of a general discussion of the inspections, monitoring, surveillance, and analyses that are documented in the BWRVIP topical reports. These topical reports have been reviewed by the staff in Section 3.1.15 of this SER and form the basis for the staff's review of the RPV monitoring program.

Fatigue Monitoring

The staff evaluation of fatigue monitoring is discussed in Sections 3.1.12, "Component Cyclic or Transient Limit Program" and 4.2, "Pipe Stress" of this SER.

Code-Required and Augmented Inspection and Pressure Tests

The staff evaluation of the Inservice Inspection Program is discussed in Section 3.1.9 of this SER.

Surveillance Material Testing

To evaluate whether the reactor vessel surveillance program will provide sufficient data for monitoring the amount of embrittlement during the license renewal term, the staff evaluates whether the surveillance program satisfies the following attributes:

> "If the ISP is not approved by the staff, and if, instead, a plant-specific surveillance material testing program is implemented, capsules must be removed periodically to determine the rate of embrittlement. Capsules must be removed at neutron fluence levels which provide relevant data for assessing the integrity of the Plant Hatch 1 and 2 RPVs; in particular, for the determination of RPV pressure-temperature limits through the period of extended operation. Capsules must contain material to monitor the impact of irradiation on the Plant Hatch RPVs and must contain dosimetry to monitor neutron fluence. If the applicant is not participating in an ISP and available capsules are not being removed from Plant Hatch during the license renewal period, the applicant must submit for staff review the technical basis for continued operation (including proposed operating restrictions, such as inlet temperature, neutron spectrum, and flux, ex-vessel dosimetry for monitoring neutron fluence, etc.)"

In response to RAI 3.1.17-1, the applicant indicated that it plans to implement the provisions of an integrated surveillance program (ISP) that is documented in BWRVIP-78, "BWR Vessel and Internals Project; BWR Integrated Surveillance Program Plan," and it's companion document, BWRVIP-86, "BWR Vessel and Internals Project, BWR Integrated Surveillance Program Implementation Plan."

In a telephone conference on November 3, 2000, the applicant clarified its commitment to participate in an ISP through the end of Plant Hatch's period of extended operation, or, if necessary, to develop a plant-specific RPV surveillance materials testing program for the period of extended operation. As part of this commitment, the staff noted that if the applicant participates in a NRC staff-approved ISP or implements a staff-approved plant specific RPV surveillance program, the ISP or plant-specific program should address the requirements of 10 CFR Part 54, including the ten aging management program attributes in the SRP-LR. Further, if the proposed program cannot meet any program attributes, the applicant should provide a technical justification for the discrepancies. This was identified as Open Item 3.1.17-1.

In response to the open item, by letter dated June 5, 2001, the applicant officially committed to implementing a staff-approved ISP for the extended period of operation based on the technical criteria of BWRVIP-78 and BWRVIP-86. The applicant further stated that, if an ISP is not approved by the NRC, or if the staff-approved ISP is not adequate for implementation at Plant Hatch, then the applicant will develop and implement a plant-specific surveillance material testing program for the extended period of operation. The applicant further stated that the plant-specific surveillance material testing program, if one is needed, will be developed in a manner consistent with other aging management programs, will include consideration of the ten program attributes utilized for other aging management programs, and will provide a technical justification for any program attribute not covered by the plant-specific surveillance material testing program.

The staff's review of BWRVIP-78 is continuing; however, all significant issues necessary for approval of BWRVIP-78 have been addressed. The proposed ISP addressed by BWRVIP-78 and BWRVIP-86, only applies to the period of the current operating licenses. The BWRVIP has committed to provide supplemental information to extend the ISP through the period of extended operation, based on the same technical criteria as found in BWRVIP-78 and BWRVIP-86, for the BWR fleet. The staff expects this supplemental information to be submitted in 2002.

Although the BWRVIP-78 and -86 reports apply only to the current term, the staff finds that the provisions in these reports, if implemented during the extended period of operation, constitute sufficient actions to manage the aging effects associated with the reactor vessel during the renewal term.

With regard to the plant-specific surveillance materials testing program, in a telephone conference on October 5, 2001, the applicant clarified its commitment that the plant-specific program, if needed, will include the following actions:

- capsules will be removed periodically to determine the rate of embrittlement

- capsules will be removed at neutron fluence levels which provide relevant data for assessing the integrity of the Plant Hatch RPVs; in particular, for the determination of RPV pressure-temperature limits through the period of extended operation

- capsules will contain material to monitor the impact of irradiation on the Plant Hatch RPVs and will contain dosimetry to monitor neutron fluence

On the basis of these commitments, the staff concludes that the applicant has identified in sufficient detail the actions that will be taken to provide reasonable assurance that aging effects associated with embrittlement of the reactor vessel will be adequately managed for the period of extended operation. On this basis, Open Item 3.1.17-1 is resolved. The renewed license will be conditioned to require that, prior to operation in the renewal term, the applicant will notify the NRC of the its decision to implement the ISP or a plant-specific program, and provide the appropriate revisions to the FSAR Supplement summary descriptions of the vessel surveillance material testing program.

3.1.17.4 Conclusion

On the basis of the acceptability of the BWRVIP reports referenced above, along with the applicants commitment to implement the actions quoted above regarding the surveillance materials testing program, the staff concludes that the RPV monitoring program is adequate to manage the aging effects associated with the components in the reactor assembly system, as required by 10 CFR 54.21(a)(3).

3.1.18 Fire Protection Activities

3.1.18.1 Introduction

The applicant described its fire protection activities program in LRA Sections A.2.1, "Fire Protection Activities"; C.2.3, "Aging Management Reviews for Fire Protection System Components"; and C.2.4, "Aging Management Reviews for Mechanical Component External Surfaces," and Section B.2.1 of the applicant's October 10, 2000 submittal. The staff reviewed the application to determine whether the applicant has demonstrated that the fire protection activities inspection program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.18.2 Summary of Technical Information in the Application

Fire protection activities comprised inspections and condition monitoring and performance monitoring activities. These activities provide assurance that a fire will not prevent the performance of necessary safe shutdown functions. The fire protection activities use both direct visual examination and indirect flow testing to detect flow blockage, loss of material, cracking, and changes in material properties. The fire protection activities are designed to minimize both the probability and consequences of postulated fires through a defense-in-depth philosophy.

Plant Hatch fire protection activities credit Appendix B of the FHA and includes passive long-lived components in water-based and gas-based fire suppression systems. In addition, the fire pump diesel fuel oil supply system (tanks and piping) and various fire rated assemblies are also included.

The water-based fire protection header loop piping is flushed regularly and the fire pump casings are visually inspected and operationally tested. The sprinklers are visually inspected and open-head sprinklers and nozzles are flow tested using air. Fire water tank internals are inspected for localized and general pitting, average dry film thickness and general condition of the protective coating. Sizes and depth of the pits are recorded. Interior surfaces are cleaned as required to facilitate inspection. Fire pump diesel fuel oil supply and various gaseous fire suppression system components are visually inspected and performance tested. In-scope fire-rated assemblies are visually inspected periodically.

3.1.18.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the fire protection activities program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

Fire protection activities are applied to the X43 - Fire Protection System which includes the following commodity groups:

- water-based fire suppression systems
- fire protection diesel fuel oil supply system
- compressed gas-based fire suppression systems
- fire barriers for preventing fire propagation
- external surfaces exposed to an inside environment
- external surfaces exposed to an outside environment

The staff requested in RAI 3.1.18-10(b) that the applicant identify the long-lived components in the water-based and gas-based fire suppression systems. In its response, the applicant stated that, "all fire-rated penetration seals, excluding those inside the radwaste building, are included in the scope of license renewal." The staff did not agree that the fire protection components that are located in the radwaste building could be excluded from the scope of license renewal. This was identified as Open Item 2.3.4.2-1. Resolution of this open item is discussed in Section 2.3.4.8 of this SER. On the basis of the resolution of this open item, the applicant has included fire protection components that are located within the radwaste building within the scope of license renewal. No new commodity groups were subject to an AMR as a result of these additional in-scope components.

Preventive or Mitigative Actions

Table C.2.3.1-1 of the LRA states that, for water-based fire suppression system components, the fire protection activities prevent or mitigate loss of material by using system flushes to remove undesirable material from the system. However, the operability of the automatic wet-pipe sprinkler systems, which are required for compliance with 10 CFR 50.48, were not discussed. In response to RAI 3.1.18-7, in which the staff notified the applicant of this omission, the applicant stated that, "unobstructed water flow from the header test valve demonstrates that sprinkler heads and piping are not clogged from corrosion product debris." The staff did not agree with this statement since (1) the arrangement of the test header at the most distant point in the sprinkler system is usually located in the fire suppression piping, which is along the path of least water resistance, and (2) the sprinkler heads are located along the smaller branch line piping and, as a result of their orientation, are typically never exposed to the flow of water during the routine testing of the test header. Since there is little or no flow in the branch lines during testing, the water in these lines remains stagnant and sediment from the raw water, which flows to the header test connection, continues to collect in the smaller branch line piping. This may result in blockage and corrosion of the branch line piping and the sprinkler heads at accelerated rates. The staff has addressed this issue in Generic Letter 89-13, "Service Water Problems Affecting Safety-Related Equipment." The staff requested that the applicant discuss the specific considerations for addressing this aging mechanism in the automatic wet-pipe sprinkler systems. This was identified as part of Open Item 3.1.18-1 [3.1.18-1(a)].

The applicant routinely performs sprinkler piping flow tests to check for clogging from corrosion products as part of the fire protection activities. The staff was initially concerned that these tests may not be adequate for demonstrating operability of the sprinkler heads during the extended period of operation. However, as the staff position has evolved, additional flow tests are not required to determine flow blockage in the sprinkler system. This is consistent with the staff position in the generic aging lessons learned (GALL) report with regard to flow blockage in fire protection and other systems, as a result of corrosion, biofouling, or silting. System flow is considered to be an active feature. However, the staff expects the applicant to be sensitive to the potential for flow degradation as a result of accumulation of corrosion products. The staff has determined that as long as the applicant conducts the wet pipe sprinkler header flow tests as described in the response to RAI

3.1.18-7, flow degradation would be adequately managed. In addition, should flow degradation be discovered, the applicant has a corrective action program, that requires trending to determine the need for future actions. On this basis, the staff concludes that Open Item 3.1.18-1(a) is closed.

Parameters Inspected or Monitored

The applicant states that surveillance and inspection of fire protection systems and components are performed in accordance with Appendix B of the FHA. Fire protection activities provide for visual inspection or performance testing for the water-based fire suppression system components and the diesel fuel oil system components. For the water-based fire suppression system, diesel fire pumps are visually inspected and operationally tested on a regular schedule, the fire water storage tank internal surfaces are periodically inspected, the sprinkler nozzles are visually inspected and air-flow-tested on a regular schedule, and valves are cycled to verify functionality. Visual inspections and performance testing of the fire protection diesel fuel oil supply system are conducted on a regular basis to detect degradation of the fuel system components prior to the loss of intended function. Visual inspections and performance testing of the compressed gas fire suppression systems and inspections of the insulation installed on the CO_2 storage tanks are conducted on a regular basis. Visual inspections are performed on fire penetration seals, in-scope cable tray enclosures and fire doors. Exterior coatings or paint are inspected per the industry guidance reflected in the protective coatings program.

The staff finds that the parameters inspected or monitored under this aging management program are adequate to ensure that aging effects will be identified for disposition through the corrective actions program.

Detection of Aging Effects

The applicant states that flow blockage, loss of material, cracking, and changes in material properties are detected directly by visual examinations of component surfaces and indirectly through the use of flow functional testing.

With regard to the inspection frequency of fire system components, the applicant lists in Section B.2.1 of the applicant's October 10, 2000 submittal the different inspection intervals for the water-based fire protection systems, fire protection pump diesel fuel oil supply system, compressed gas based fire suppression systems, fire penetration seals, cable tray enclosures, and fire doors. In addition to the systems listed above, the applicant describes a one-time inspection called the "Sprinkler Head Inspections" that will be performed at or before the start of the extended period of operation for closed sprinkler heads within the scope of license renewal. In RAI 3.1.18-9, the staff requested that the applicant provide justification for the absence of enhanced inspection programs for the sprinkler heads, which do not have a design life that covers the period of extended operation. In response the applicant stated that, in general, enhanced inspection programs are deemed unnecessary because the existing programs adequately manage the aging effects of concern, and that using the guidelines of the National Fire Protection Act (NFPA) Code 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection," a one-time sprinkler heads inspection is to be performed for in-scope sprinkler heads. The staff does not agree that a one-time inspection is sufficient for the sprinkler heads and recommends that the applicant expand the scope of its inspections to include the 10-year inspection intervals that are recommended in NFPA 25, Section 2.3.3.1, "Sprinklers." Section 2.3.3.1 states that "where sprinklers have been in place for 50 years, they shall be replaced, or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing." It also contains guidance to perform this sampling every 10 years after the initial field service testing. In addition, the staff has notified the nuclear industry, through recent information notices, about the potential failures associated with sprinkler heads. These information notices include IN 01-10, "Failure of Central Sprinkler Company Model GB Series Fire Sprinkler Heads;" IN 99-28, "Recall of Star Brand Fire Protection Sprinkler Heads;" and IN 97-72, "Potential for Failure of the Omega Series Sprinkler Heads." Problems with seals leaking and sprinkler heads failing to actuate are typically not detectable through the performance of existing visual inspections. Therefore, the staff requested that the applicant expand the scope of its inspections to include the 10-year inspection intervals that are recommended in NFPA 25 or provide additional justification for the applicant's proposed inspection interval. This was identified as part of Open Item 3.1.18-1 [3.1.18-1(b)].

The applicant has previously addressed this issue in its responses to RAIs 2.3.4-FPS-10 and 3.1.18-9. By letter dated June 5, 2001, in response to Open Item 3.1.18-1(b), the applicant supplemented the earlier RAI responses by expanding the scope of the inspections referenced. Thus, the revised commitment is to use the guidance of NFPA-25 to perform an inspection of closed head sprinklers after 50 years of service and at 10-year intervals thereafter. On the basis of the applicant's commitment, the staff finds that the applicant has adequately addressed the staff's concern and Open Item 3.1.18-1(b) is closed.

Monitoring and Trending

The applicant states that the results of fire protection system tests and inspections are documented in accordance with procedural requirements. In addition, the corrective actions program is used to monitor and trend fire protection deficiencies and to implement timely corrective actions. The staff finds that the monitoring and trending activities described by the applicant are adequate to ensure that corrective actions will be taken before exceeding the acceptance criteria.

Acceptance Criteria

The applicant states that significant degradation of components managed by this aging management program are noted and corrective actions are implemented on the basis of the corrective actions program. Acceptance criteria for each test or inspection is specifically stated in plant procedures and includes system frictional pressure drop; adequate air flow; detection of leaks present; sampling for water, sediment, and other oil contaminants; and CO_2 tank pressure, general condition, and pressure boundary leakage.

Based on the discussion above and the operating history of this aging management program, the staff finds that the acceptance criteria established in plant procedures reasonable to detect aging effects which were evaluated by the corrective actions program before failure occurred.

Operating Experience

For the water-based fire suppression systems, deficiencies included leaking piping, deterioration of coatings within the fire water storage tank, and fouling of lines attributable to corrosion buildup. These were identified during testing and inspection as required by the fire protection activities or normal walk down activities.

Per LRA Section C.2.3.2, IN 91-46 identified a potential deficiency managed in the fire protection activities. This potential deficiency is clogging of strainers with sediment and degraded fuel oil. Deficiencies of the external surfaces are managed by the applicant's protective coatings program.

The staff concludes that the operating experience, to date, supports the attributes of the fire protection activities.

3.1.18.4 Conclusions

The staff has reviewed the fire protection activities for the aging management program described in LRA Sections: A.2.1, "Fire Protection Activities;" C.2.3, "Aging Management Reviews for Fire Protection System Components;" and C.2.4, "Aging Management Reviews for Mechanical Component External Surfaces," and Section B.2.1 of the applicant's October 10, 2000 submittal. On the basis of its review, the staff concludes that the fire protection activities program will adequately manage the identified aging effects for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.19 Flow Accelerated Corrosion Program

3.1.19.1 Introduction

The applicant described its flow-accelerated corrosion (FAC) program in LRA Sections A.2.2, "Flow Accelerated Corrosion Program," and Section B.2.2 of the applicant's October 10, 2000 submittal. It also included relevant materials from Section 3.2.1, "Reactor," Section 3.2.3, "Engineering Safety Features (ESF) System," and Section 3.2.5, "Steam and Power Conversion." These sections address aging effects of the components in reactor, engineering safety features, and steam and power conversion systems. The components in these systems belong to two commodity groups, one representing Class 1 carbon steel components within the reactor water environment, and the other, non-Class 1 carbon steel components within the reactor water environment. Both of these commodity groups contain components that are subject to aging effects managed by the FAC program. The objective of this program is to ensure that the damage caused by flow-accelerated corrosion will not cause component failures. This objective is accomplished by predicting the rate of degradation of components and taking corrective actions once the degradation is detected.

The staff reviewed the applicant's description of the program in LRA Sections A.2.2, Section B.2.2 of the applicant's October 10, 2000 submittal, and relevant material in other referenced sections of the LRA to determine whether the applicant has demonstrated that the program will adequately manage the effects of aging caused by FAC in the plant during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.19.2 Summary of Technical Information in the Application

In the LRA the applicant has identified the following systems which contain the components that are affected by FAC:

- nuclear boiler system
- high pressure coolant injection system
- reactor core isolation system
- main condenser

The applicant identified loss of material by FAC as the aging effect for carbon steel components exposed to reactor water. (However, main steam piping is not susceptible to FAC.)

In the LRA, the applicant identified a FAC program for managing the aging effects caused by FAC. The program is predicated on EPRI recommendations for effective control of FAC. For license renewal, the applicant will enhance the existing program by adding components in certain systems which are already included in the FAC program. For Unit 2, these systems will consist of portions of the radioactive decay holdup volume (main steam and steam line drains, and condensate drains). Also, it will enhance examination methods and frequencies for the components, such as smaller-than-two-inch piping, whose FAC wall thinning could not be predicted by the computer code used in the program. Examinations of these components will be predicated on industry and plant-specific operating experience as opposed to computer modeling. The applicant concluded that this enhanced program will adequately manage aging effects in the components affected by FAC.

3.1.19.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the FAC program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

The components in the systems affected by FAC are made of carbon steel. This material, when exposed to the environment of moving single or two-phase reactor water with relatively low oxygen content and high temperature, corrodes at rates higher than if it were in contact with a stagnant fluid. The resulting loss of material produces thinning walls in the affected components. To prevent component failure, loss of material has to be managed. The staff finds that there is reasonable assurance that this mode of degradation is the only plausible aging effect related to FAC for aging management considerations.

The applicant has a program for managing aging effects attributable to FAC. The program is predicated on the EPRI recommendations, specified in Report NSAC-202L, "Recommendations for an Effective Flow-Accelerated Corrosion Program," and in the associated CHECWORKS computer code. The program predicts, detects, and monitors flow accelerated corrosion wear in high-energy carbon steel piping in the nuclear boiler system, high pressure coolant injection system, reactor core isolation system, and main condenser. It includes determination of the extent of wall thinning in the FAC-affected components and specifies repair or replacement of the components with wall thickness not meeting the acceptance criteria.

Program Scope

The applicant will enhance the existing program during the period of extended operation, starting midnight August 6, 2014, for Unit 1 and midnight June 13, 2018, for Unit 2. The enhancement includes additional components for inspection, and adds an inspection method for the components which could not be inspected by the method presently existing in the program. The staff finds that the enhanced scope of the program will be adequate for managing loss of material due to FAC.

Preventive and Mitigative Actions

The FAC program is designed to monitor the aging effects attributable to FAC before a loss of intended function. The staff agrees that the FAC program is not intended to prevent or mitigate the effects associated with FAC. Instead the program is designed to monitor the aging effects attributable to FAC. The staff concludes that the program will provide assurance that FAC will be adequately monitored.

Parameters Monitored or Inspected

The FAC program monitors the effects of FAC by measuring wall thickness of the components exposed to the environment favoring FAC. Analytical models are used to predict wall thinning in piping systems susceptible to FAC on the basis of the specific plant data, including material of construction, chemistry, and hydrodynamic and operating conditions. The subsequent examination of the selected components is made by visual, ultrasonic, or radiographic techniques. The staff finds this methodology adequate to detect the aging effects attributable to FAC.

Detection of Aging Effects

Wall thickness is measured by ultrasonic testing or, in the case of small-bore pipes, by radiography since ultrasonic testing of small-bore pipes is impractical. The staff finds these to be standard, well developed techniques that will produce reliable results.

Monitoring and Trending

Using the methods stated above, the applicant will be able to evaluate the rate at which component wall thinning by FAC is occurring. The CHECWORKS computer program contains a database that maintains inspection data which can be used for that purpose. Trending the data will permit determination of the timing for future inspections. Also, if degradation is detected such that the wall thickness may reach a value below the minimum allowed by the acceptance criteria, the component will be repaired or replaced, and additional examinations will be performed of the components in the adjacent areas to bound the damaged component. The staff finds adequate the monitoring and trending method and subsequent actions.

Acceptance Criteria

The criteria for component replacement are predicated on allowable minimum wall thickness, determined by the design code of record. If the predictive methods indicate that a component will reach its minimum allowable wall thickness before the next inspection interval, proper corrective actions will be undertaken. The staff finds the acceptance criteria adequate.

Operating Experience

The applicant monitors the FAC-related developments occurring in the industry. This is accomplished through contacts with EPRI and review of the information generated by the industry. Additionally, EPRI NSAC-202L provides lessons learned from years of industry-wide operating experience which could be used to improve the FAC program. A review of plant data for the past 5 years has revealed FAC damage in small bore piping of the HPCI and RCIC main steam supply drain to the condenser. The damaged components were replaced with material not susceptible to

FAC. Also, as a result of FAC program inspection and corrective action implementation, the high-pressure drain manifold was replaced with chrome-moly piping. The staff finds that plant experience has indicated that the FAC program is successful in managing aging caused by FAC.

3.1.19.4 Conclusions

The staff has reviewed the information in LRA Section A.2.2, "Flow-Accelerated Corrosion Program," and Section B.2.2 of the applicant's October 10, 2000 submittal. On the basis of its review, the staff concludes that the applicant has demonstrated that the flow accelerated corrosion program will adequately manage aging effects caused by flow accelerated corrosion for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.20 Protective Coatings Program

3.1.20.1 Introduction

The applicant described the protective coatings program in LRA Section A.2.3 and Section B.2.3 of the applicant's October 10, 2000 submittal. The staff reviewed the application to determine whether the applicant has demonstrated that the protective coatings program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.20.2 Summary of Technical Information in the Application

The protective coatings program provides a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the associated environment. It is a mitigation and condition monitoring program designed to provide base metal aging management through application, maintenance, and inspection of protective coatings on selected components and structures.

The protective coatings program will be expanded to include the external surfaces of carbon steel commodities in-scope for license renewal that are exposed to inside, outside, submerged, and buried environments, as made accessible. Portions of multiple systems will be included, consistent with plant-specific operating experience and conditions. Affected systems will include, but may not be limited to, the nuclear boiler, standby liquid control, residual heat removal, residual heat removal service water, core spray, high pressure coolant injection, and reactor core isolation cooling. Certain portions of the post-accident radioactive decay holdup, PSW, instrument air, drywell chilled water, drywell pneumatics, standby gas treatment, nitrogen inerting, fire protection, and diesel fuel oil systems, as well as piping supports, raceway supports, and building structural steel will also be included. The affected components in these systems will be piping, valves, pumps, bolts, tanks, and structural steel.

The protective coatings program will be revised to require periodic inspections of in-scope components to ensure that they are properly coated and free of significant age-related degradation. Coated surfaces of certain components, including those that are normally inaccessible but made accessible as a result of maintenance or other activities, will also be inspected when they become accessible.

Program expansions and revisions will be implemented by midnight August 6, 2014, for Unit 1 and common system components, and midnight June 13, 2018, for Unit 2.

3.1.20.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the protective coatings program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The protective coatings program provides a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the associated environment. It is a mitigation and condition monitoring program designed to provide base metal aging management through application, maintenance, and inspection of protective coatings on selected components and structures.

The systems where the protective coatings program is applied are:

B21 - Nuclear Boiler
C41 - Engineered Safety Features
C11 - Control Rod Drive
E11 - Residual Heat Removal
E21 - Core Spray
E41 - High Pressure Coolant Injection
E51 - Reactor Core Isolation Cooling
F15 - Refueling Equipment
H11 - Main Control Room Panels
H21 - In Plant Auxiliary Control Panels
L35 - Pipe Specialties
L48 - Access Doors
N61 - Main Condenser
P41 - Plant Service Water
P42 - Reactor Building Closed Cooling Water
P52 - Instrument Air
P64 - Primary Containment Chill Water
P70 - Drywell Pneumatic
R33 - Conduits, Raceways, and Trays
T23 - Primary Containment
T24 - Fuel Storage
T29 - Reactor Building
T31 - Cranes, Hoists, and Elevators
T52 - Drywell Penetrations
T54 - Reactor Building Penetrations
T41 - Reactor Building HVAC
T48 - Primary Containment Purge and Inerting
T49 - Post LOCA Hydrogen Removal
U29 - Turbine Building
W33 - Traveling Water Screens, Trash Racks
W35 - Intake Structure
X41 - Outside Structures HVAC

X43 - Fire Protection
Y29 - Yard Structures
Y32 - Off Gas Stack
Y39 - EDG Building
Y52 - Fuel Oil
Z29 - Control Building
Z41 - Control Room HVAC

The staff agrees that it is appropriate to include the systems listed above within the scope of the program.

Preventive or Mitigative Actions

The applicant states that the protective coatings program is a mitigation program designed to provide metal aging management through application, maintenance, and inspection of protective coatings on selected components and structures. The staff agrees that a properly developed coating program that is properly implemented, constitutes a mitigative action.

Parameters Inspected or Monitored

The parameters inspected are the condition of coatings on the systems listed above. This includes bolts and base metal surfaces exposed to inside, outside, submerged, and underground environments.

The applicant stated that a protective coatings surveillance is normally performed once per operating cycle for service level I components (service level I components are used in areas inside the reactor containment where failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown). Other component surveillance is performed as determined by the protective coatings specialist, consistent with trends and plant specific operating experience. The applicant stated that there will be a baseline inspection of all in-scope coated components, with the exception of buried piping, which will be inspected as available as a result of excavation activities. Subsequent inspection frequencies will be determined on the basis of the results of the baseline inspection. The staff agrees that the parameters inspected are appropriate.

Detection of Aging Effects

The applicant states that aging effects are detected using visual examinations. The staff agrees that visual inspections are appropriate for bolts and base metal surfaces exposed to inside, outside, and submerged environments since this is a common and accepted practice. Visual inspections are also appropriate for buried commodities for identifying damaged or degraded coatings and any subsequent loss of material attributable to corrosion.

Monitoring and Trending

Results of coatings inspections are documented in accordance with Plant Hatch procedural requirements. For service level I coatings, a record will be kept concerning locations of minor deterioration, and subsequent evaluation. For all coatings, a summary of findings and recommendations for future actions will be maintained. Significant degradation identified during coatings inspections are also identified utilizing the Plant Hatch corrective actions program.

A baseline inspection of all in-scope coated components will be performed, with the exception of buried piping that will be inspected as available during excavation activities. Subsequent inspection frequencies will be determined on the basis of the results of the baseline inspection. The staff concludes that the monitoring and trending are adequate.

Acceptance Criteria

Multiple codes and standards were considered in the development of the plant protective coatings program. These include ANSI N5.12 – 1972, "Protective Coatings (Paints) for the Nuclear Industry"; ANSI N101.2 – 1972, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities"; ASTM, Section 6, Volume 06.02, "Paints-Products and Applications, Protective Coatings, Pipeline Coatings"; AWWA C203, "Coal-Tar Protective Coatings for Steel Water Pipelines - Enamel and Tape - Hot Applied"; and AWWA C209, "Cold Applied Tape Coatings for the Exterior of Special Sections, Connections, and Fittings for Steel Water Pipelines."

Coatings application is not allowed to proceed until applicable solvent cleaning, removal of stratified rust, loose mill scale, non-adherent paint, weld flux and splatter, and thick edge paint feathering has been verified. Prepared steel must conform to SSPC-SP11 (Steel Structures Painting Council) visual standards SSPC-VIS3, or equivalent.

The staff has reviewed the references and agrees that the acceptance criteria in the references provides reasonable assurance that the acceptance criteria are effective in controlling the aging effect of loss of material.

Operating Experience

The applicant reviewed plant deficiency cards submitted over the past 5 years which identified many instances of coating degradation. Primarily, these deficiencies related to corrosion of carbon steel and low-alloy components in areas where the existing coating had broken down, no coating was originally applied, or wetting attributable to leakage had occurred.

Relevant operating experience for in-scope buried piping is limited to PSW, RHRSW, and diesel fuel oil supply piping since no credit was taken for the coatings installed on fire protection cast iron piping. A review of more than 36,000 plant deficiency cards and interviews with key personnel revealed no age related failures of piping attributable to coating degradation over the past 5 years.

Based on the applicant's review of plant records, the staff finds that the coating program will adequately manage the effects of aging for the period of extended operation.

3.1.20.4 Conclusions

The staff has reviewed the information in Section A.2.3, "Protective Coatings Program," of the LRA, the applicant's responses to the staff's RAIs, and Section B.2.3 of the applicant's October 10, 2000 submittal. On the basis of its review, the staff concludes that the applicant has demonstrated that the effects of aging associated with structures and components in systems managed by the protective coatings program will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.21 Equipment and Piping Insulation Monitoring Program

3.1.21.1 Introduction

The applicant described its equipment and piping insulation monitoring program in LRA Sections A.2.4, C.2.4.4, C.2.4.4.1 and C.2.4.4.2. Supplemental information is further provided in Section B.2.4 of the October 10, 2000, submittal, which provided the applicant's responses to the staff's RAI. The equipment and piping insulation monitoring program at Plant Hatch is a condition monitoring program designed to detect insulation damage through periodic inspection of specific passive component insulation. The staff reviewed the application to determine whether the applicant has demonstrated that the program will adequately manage aging effects for the affected equipment and piping during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.21.2 Summary of Technical Information in the Application

The applicant stated that equipment and piping insulation includes insulation and associated jacketing for in-scope components installed on emergency core cooling system (ECCS), PSW and RHR service water system components. Thermal insulation serves to maintain design calculation limits, provide freeze protection, and prevent overheating of ECCS diagonals and HPCI pump rooms. The metallic jackets and fasteners serve to protect the insulation from environmental attack and fix the insulation in place.

3.1.21.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the equipment and piping insulation monitoring program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

The applicant stated that for insulation, aging effects requiring management include loss of material as a result of wear and intrusion of water borne agents; cracking as a result of thermal effects and intrusion of water borne agents; and change in material properties as a result of compaction and settling, material separation, intrusion of water and water-borne agents, and thermal effects. The applicant also stated that the in-scope insulation jacketing components and associated fasteners are fabricated from stainless steel, galvanized steel, and aluminum alloys. The aging effects requiring management for these materials include loss of material as a result of general corrosion, galvanic corrosion, pitting, crevice corrosion and MIC, and cracking as a result of thermal fatigue.

Program Scope

The equipment and piping insulation monitoring program currently inspects insulation of piping and equipment within the scope of license renewal. The applicant stated that the program will be enhanced to include portions of the following systems that are within the scope of license renewal:

C41 - SLC
E11 - RHR and RHRSW
E21 - core spray
E41 - HPCI

E51 - RCIC
P11 - condensate transfer and storage
P41 - PSW
X43 - fire protection

The applicant indicated that program enhancements will be implemented by midnight August 6, 2014, for Unit 1, and midnight June 13, 2018, for Unit 2. The staff finds that the scope of the program will be adequate for managing the aging of insulation within the scope of license renewal.

Preventive or Mitigative Actions

In Section C.2.4.4, the applicant stated that no reasonable method is available to mitigate potential deterioration of insulation at Plant Hatch. However, it is expected that deterioration of insulation at Plant hatch will occur slowly and would be adequately managed by a focused inspection program provided by the equipment and piping insulation monitoring program. Therefore, no program is required to prevent or mitigate aging degradation. Plant Hatch procedures contain precautions limiting climbing on pipe insulation unless specifically justified by an engineering review and evaluation. Damage is further mitigated by procedures that provide specific instructions for removal, storage, and installation of thermal and reflective insulation. The staff finds there are no preventive or mitigative attributes associated with this program. The licensee will inspect the in-scope insulation for deterioration.

Parameters Inspected or Monitored

The applicant stated that the equipment and piping insulation monitoring program will be enhanced to periodically inspect in-scope insulation that is readily accessible to identify any holes, tears, compaction, material separation, wetting, missing insulation and general deterioration. Aluminum and galvanized steel insulation jackets and their binders will be inspected for cracking and loss of material. The staff finds the examination of in-scope insulation is adequate for detecting degradation of the insulation.

Detection of Aging Effects

The applicant stated that appropriate visual inspection techniques will be used for the inspection. These techniques will include remote visual inspection using binoculars or other devices for some locations. The exterior surfaces of the insulation system are visually inspected for obvious degradation. Exterior surfaces may consist of protective metal jacket covers that are not removed unless there is obvious degradation or evidence of a problem in the underlying insulation, such as significant corrosion or water egress from within the jacketing system. Once degradation is found, the outer metal jacket may be removed to further investigate the underlying insulation material condition. All in-scope external jackets and binders are visually inspected for holes, tears, cracks, significant corrosion, missing material, and generally deteriorated condition. When warranted by external inspection, the affected underlying insulation material is visually inspected for holes, tears, compaction, material separation, wetting, missing insulation, and generally deteriorated condition as a result of cracking, settling, and thermal degradation. The applicant stated that none of these conditions (holes, tears, cracks, missing material, etc.) is acceptable. If degradation is discovered, corrective action will be initiated to remedy the condition. Since the entire in-scope insulation system, to the extent it is accessible, is inspected, there is no sample size. The staff finds this approach reasonable.

Monitoring and Trending

The applicant stated that deficiencies discovered during these insulation inspections will be documented in accordance with the Plant Hatch corrective actions program. For outside insulation and jackets, the frequency of inspections is once per year. For inside insulation and jackets, all in-scope insulation is to be inspected within 2 refueling cycles of issuance of the new operating license and at least once every 10 years thereafter. The staff finds this approach reasonable.

Acceptance Criteria

The applicant stated that any unacceptable indication of corrosion or insulation damage will be evaluated and, if warranted, additional inspections will be performed. Unacceptable conditions include holes, tears, cracks, missing material, etc. Corrective actions, if required, will be addressed through the existing Plant Hatch corrective actions program. The applicant stated that the plant procedures specify the acceptance criteria for the equipment and piping insulation, including insulation jackets. The staff concurs with the applicant that these criteria will ensure that degraded insulation will be managed properly.

Operating Experience

A review of plant deficiency cards over the past 5 years did not identify any significant age-related degradation in insulation or insulation jacketing for the components within the scope of license renewal. The applicant stated that several deficiencies were identified related to damaged, torn, or missing insulation. These areas were localized, generally attributed to mechanical damage, and not deemed to significantly impact thermal performance of the insulated system. Only one record that related to generally deteriorated insulation was discovered. This deterioration was confined to a small area and was not determined to significantly affect the thermal performance of the insulated system. Given the applicant's operating history, the staff finds that the equipment and piping insulation monitoring program will adequately manage aging effects associated with insulation and jackets for the period of extended operation.

3.1.21.4 Conclusions

The staff has reviewed the information in Section A.2.4, of the LRA, "Equipment and Piping Insulation Monitoring Program," and Section B.2.4, "Equipment and Piping Insulation Monitoring Program," of the applicant's October 10, 2000 submittal. On the basis of its review, the staff concludes that the applicant has demonstrated that the effects of aging associated with the insulation of piping and equipment in systems managed by this program will be adequately managed such that the insulation and jacketing will continue to perform their intended functions, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.22 Structural Monitoring Program

3.1.22.1 Introduction

The applicant described its structural monitoring program in LRA Section A.2.5, and supplemented its description of this AMP in Section B.2.5 of the October 10, 2000 submittal. The applicant credits this inspection program with assessing the overall conditions of buildings and structures and identifies any ongoing degradation through a visual inspection process. The program monitors and assesses the condition of structures affected by aging, which may cause loss of material, cracking, loss of adhesion, and change of material properties. The staff reviewed the application to determine whether the applicant has demonstrated that the structural monitoring program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.22.2 Summary of Technical Information in the Application

In LRA Section A.2.5 and Section B.2.5 of its October 10, 2000 submittal, the applicant describes an existing aging management program, the structural monitoring program, that provides for periodic visual inspections to monitor the condition of structures, components, and commodities. The monitored structures include the switchyard, reactor buildings, turbine buildings, intake structure, main stack, diesel generator building, control building, and waste gas building. In addition, the condensate storage tank foundation and walls, plant service water valve pits, and nitrogen storage tank foundations are also monitored by the structural monitoring program. The applicant lists the specific structural components, which are fabricated from either carbon steel, stainless steel, or concrete, and inspected as part of the structural monitoring program in LRA Sections 3.2 through 3.4.

The aging effects managed by the structural monitoring program are discussed in LRA Section C.1.4. The structural monitoring program is relied on for management of loss of material attributable to general corrosion for steel structures in seismic Category I buildings, the turbine building, Category I yard structures and component supports. For concrete components (i.e., walls, beams, slabs, columns, floors, roof, underground duct runs and pull boxes, foundations) and block walls in concrete structures, the structural monitoring program is relied on for management of cracking and spalling resulting from corrosion for embedded steel, and cracking in masonry block walls. In response to RAI 3.4-PSW-3, the applicant indicated that pit and diving activities originally listed under the SMP will now be done in the PSW and RHRSW inspection program, which is described in LRA Section B.1.13. The pit inspection and diving activities help manage flow blockage by removal of accumulated silt and debris from the intake structure pump suction pit. In addition, the structural monitoring program also manages loss of adhesion, material property changes, and cracking of the reactor building joint seal and caulk sealant. The applicant states that the structural monitoring program is patterned after the Westinghouse Owners Group Life Cycle Management/License Renewal Program. The structural monitoring program is an existing program that will be enhanced for license renewal to include the inspection of sealants in the joints between the reactor building exterior precast siding panels and seismic Category I and seismic Category II/I piping, cable trays, conduits, control room panels, auxiliary panels, and their supports. These program enhancements will be implemented by August 6, 2014, for Unit 1 and by June 13, 2018, for Unit 2.

3.1.22.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the structural monitoring program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The applicant lists the structures, components, and commodities that are covered by the structural monitoring program in Section B.2.5 of the October 10, 2000 submittal. In Open Item 3.6.3.1-1, the staff was concerned that there was no demonstration that the leakage characteristics of the reactor building would be maintained during the extended period of operation. By letter dated June 5, 2001, the applicant responded to this open item, stating that the structural monitoring program would be revised to include the provisions of Surveillance Requirement 3.6.4.1.4 of the Unit 1 and 2 technical specifications (TS). The draw-down test performed pursuant to the surveillance requirement will be credited for aging management as an additional detection measure that is capable of detecting gross changes in flow that may be indicative of age-related degradation. The applicant also revised the FSAR Supplement to reflect this change.

On the basis of the applicant's inclusion of the secondary containment draw-down test as per the surveillance requirements of the TS, as a means to detect gross age-related degradation of secondary containment, the staff concludes that the applicant has an adequate AMP to demonstrate that the overall effect of numerous degradations will not violate the leakage characteristics of the reactor building.

The staff finds that the scope of the structural monitoring program is acceptable since it includes a walkdown inspection of all structures and components within the scope of license renewal and includes a draw-down test to confirm that the leakage characteristics of the reactor building will be maintained during the extended period of operation.

Preventive and Mitigative Actions

There are no preventive or mitigative actions taken as part of this program, and the staff did not identify the need for such actions.

Parameters Inspected or Monitored

The structural monitoring program requires a visual inspection of structures and components. Specifically, the applicant stated that (1) concrete structures are inspected for cracking and spalling, (2) masonry block walls are inspected for cracking, (3) steel structures and components are inspected for corrosion, (4) panel joints, seals, and sealants are inspected for loss of adhesion, material property changes, and cracking, and (5) acrylic domes on the tornado vents will be inspected for cracking. For structures located below ground or embedded, the applicant stated that when normally inaccessible structures are exposed because of excavation or modification, an examination of the exposed surfaces is performed. This approach is acceptable to the staff. The staff finds the parameters monitored, such as cracking and spalling of concrete, and corrosion of steel, acceptable because they are directly related to the degradation of civil structures and components, and visual inspections are effective and adequate to detect such conditions.

Detection of Aging Effects

The aging effects that are managed by the structural monitoring program are identified through visual inspections. In response to RAI 3.1.22-5, the applicant stated that the implementing document for the structural monitoring program provides a detailed description of the walkdown procedures, acceptance criteria, evaluation of results, and checklists. In response to RAI 3.1.22-4, the applicant stated that structural monitoring is performed by qualified personnel, using inspection tools. In addition, all inspection results are documented and noted degradation may be documented utilizing digital photography. With respect to the inspection frequency, the applicant stated that a 5 operating cycle inspection frequency was established for the structural monitoring program. In addition, the applicant stated that this frequency will continue unless the conditions, environment, or noted degradation warrant a change. The intake structure is inspected during every operating cycle because of the humid environmental conditions; however, given the results of future intake structure inspections, the monitoring program may go to a 5 operating cycle frequency. The applicant's operating experience to date supports the continuation of a 5-year frequency for inspections. Furthermore, the staff finds that the 5 operating cycle frequency is consistent with industry experience and is, therefore, acceptable.

Monitoring and Trending

The applicant did not identify any monitoring and trending activities in its description of the structural monitoring program; however, in response to RAI 3.1.22-2, the applicant stated that structures are monitored for changes in previously identified findings and for newly developed conditions. Trending of such findings is performed to predict degrading conditions and to determine the potential long-term impact of the finding. The staff finds that the monitoring and trending activities described by the applicant are adequate to ensure that corrective actions will be taken before exceeding the acceptance criteria.

Acceptance Criteria

The applicant did not identify any specific acceptance criteria in its description of the structural monitoring program; however, in response to RAI 3.1.22-1 the applicant identified the following criteria:

- Concrete is inspected for spalling (> 3/4" in depth and 8" in dimension), cracking (> 0.04" in width), exposed rebar that has not progressed and has not resulted in loss of cross section greater than 10 percent, and signs of separation or environmental degradation present in joints or joint materials.

- Masonry walls are inspected for cracks, for appropriate anchoring, for lateral supports for seismic block walls, and for evidence of damage or movement in the interfaces between the block walls and concrete floors.

- Structural steel is inspected for general corrosion (flaking rust, surface stains, spots) and localized corrosion with the presence of small diameter pitting or the presence of loose rust flakes peeling or blooming from metal surfaces.

In addition, in response to RAI 3.1.22-3, the applicant stated that the acceptance criteria for the structural monitoring program are consistent with the recommended criteria in ACI 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," and also include additional criteria for roof ponding, water leakage, coatings, penetration seals, etc. The applicant also stated that the results of the inspections are evaluated in accordance with the guidance given in NEI 96-03, "Guideline for Monitoring the Condition of Structures at Nuclear Power Plants" and NRC Regulatory Guide 1.160 (Revision 2), "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The staff has not accepted the NEI 96-03 guideline for use in license renewal (letter from Thomas

T. Martin, NRC, to Thomas E. Tipton, NEI, dated October 1, 1996). NRC Regulatory Guide 1.160 endorses NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Although the staff has not accepted NEI 96-03, the staff finds that the acceptance criteria specified above are adequate to ensure that the structure and component intended function(s) are maintained under all CLB design conditions during the period of extended operation.

Operating Experience

In LRA Section B.2.5 of the applicant's October 10, 2000 submittal, the applicant stated that in 1996 and 1997 an initial inspection was performed to establish the baseline condition of the buildings and structures within the scope of the structural monitoring program. Areas were visually inspected and photographs were made to document any notable degradation. The applicant found that all inspected areas were within the limits of the acceptance criteria. The staff finds that the applicant's operating experience has demonstrated that the structural monitoring program has effectively maintained the integrity of the structures and components and that the effects of aging will be adequately managed during the period of extended operation.

3.1.22.4 Conclusions

The staff has reviewed the information in LRA Sections A.2.5, "Structural Monitoring Program," of the LRA, and B.2.5, "Structural Monitoring Program," of the applicant's October 10, 2000 submittal. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects managed by the structural monitoring program will be adequately managed so that there is reasonable assurance that the commodities and components covered by this inspection program 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).

3.1.23 Galvanic Susceptibility Inspections

3.1.23.1 Introduction

The applicant described the galvanic susceptibility inspection program in LRA Section A.3.1 and Section B.3.1 of the applicant's October 10, 2000 submittal. The program is described under A.3 "New Programs and Activities" of the Final Safety Analysis Report Supplement. The program is aimed at verifying the integrity of the components subject to galvanic corrosion. The staff reviewed this section of the application to determine whether the applicant demonstrated that the effects of aging caused by galvanic corrosion will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.23.2 Summary of Technical Information in the Application

LRA Section A.3.1 and Section B.3.1 of the applicant's October 10, 2000 submittal include a discussion of the galvanic susceptibility inspection program, which determine the acceptability of the components that are exposed to galvanic corrosion. This type of corrosion occurs when two electrically coupled metal surfaces characterized by different corrosion potentials are exposed to an electrolyte. In this situation, a less noble material (carbon steel for example) will corrode. The applicant has identified three types of galvanic couples at Plant Hatch: carbon steel-stainless steel, aluminum alloy-galvanized steel and galvanized steel-stainless steel. The carbon steel-stainless steel couple exposed to an electrolyte is most conducive to galvanic corrosion since these two materials are far apart in the galvanic series. The LRA has identified some of the carbon-to-stainless steel connections (welded or flanged) exposed to corrosive environments that are susceptible to galvanic corrosion in the following systems: nuclear boiler, CRD, RHR, HPCI, RCIC, main condenser, PSW, EDG, primary containment, containment atmospheric control, and screen wash isolation. Some dissimilar metal connections of aluminum alloy-galvanized steel, and galvanized steel-stainless steel used in the CST are also susceptible to galvanic corrosion.

The applicant's galvanic susceptibility inspection program is a one-time inspection for condition monitoring that will provide objective evidence that the galvanic susceptibility is being maintained for the specific components within the scope of license renewal. Since galvanic corrosion is most likely to occur in commodities within environments that are highly corrosive (high impurity and conductivity levels), these inspections will start with the corrosive raw water environment. The galvanic susceptibility inspection will utilize a volumetric examination method for a sample population of carbon-to-stainless steel weld connections for thickness measurements using an ultrasonic or radiographic technique, or a depth gauge, where feasible, or by the removal of a specimen and conducting an analysis. This inspection may also utilize an examination method similar to that described for the VT-1 visual examination of the ASME Code, Section XI. Any unacceptable indication of loss of material will be evaluated by an engineering analysis and, if warranted, additional inspections will be performed. The results of examination will also be evaluated to determine whether the sample set should be expanded to cover other environments. The applicant will implement corrective actions through the existing Plant Hatch corrective actions program.

3.1.23.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the galvanic susceptibility program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The galvanic susceptibility inspections are one-time inspections of a given sample that are intended to provide objective evidence that the applicable aging effects are being adequately managed. In this program, the applicant has stated that it would provide for the condition monitoring of the components within the scope of license renewal to determine whether galvanic corrosion is being managed for the period of extended operation. This determination will be achieved by inspecting selected components. Samples for inspection will be selected from raw water carbon steel-to-stainless steel weld connections since these two materials are the farthest apart in the galvanic series, and therefore have the greatest potential for galvanic corrosion. Examination results will be evaluated to determine whether the sample set should be expanded to other environments. The staff finds the scope of the program to be adequate because it bounds the galvanic corrosion rates occurring in other components within the scope of license renewal and, therefore, provides for meaningful detection of age-related damage caused by galvanic corrosion. The applicant stated that the Unit 1 inspections will be performed on or after August 6, 2009, but before midnight August 6, 2014. Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018.

Preventive or Mitigative Actions

There are no activities in the galvanic susceptibility inspection program with regard to preventive or mitigative actions. The staff did not identify the need for such actions.

Parameters Inspected or Monitored

The applicant stated that the galvanic susceptibility inspections are one-time inspections that will focus on whether there is loss of material due to galvanic corrosion. Appropriate examination methods will be utilized and inspection locations will be selected for thickness measurement. The staff finds this approach to be acceptable.

Detection of Aging Effects

Volumetric examination will be conducted for a sample population of the carbon to stainless steel weld connections for thickness measurements using an ultrasonic or radiographic technique, or a depth gauge, where feasible, or by removing of a specimen and conducting an analysis. The inspection may also utilize an examination method similar to that described for the VT-1 visual examination of the ASME Code, Section XI. The wall thickness inspection of the representative sample will determine the loss of material due to galvanic corrosion and, hence, assess the impact of this aging effect on other components of the plant included in the LRA. The staff finds this to be acceptable.

Monitoring and Trending

There are no activities in the galvanic susceptibility inspection program with regard to monitoring and trending. The staff did not identify the need for such.

Acceptance Criteria

The acceptance criteria will be based on the applicable sections of the design codes. The program also requires that corrective action be taken if any unacceptable condition of loss of material is detected. The staff finds that, as proposed by the applicant, an engineering analysis followed by implementation of specific corrective actions specified by the site-controlled corrective action program, will provide an acceptable technical basis for management of the aging effects caused by galvanic corrosion.

Operating Experience

The applicant conducted a review of records dating back 5 years on the components within the scope of license renewal to determine deficiencies related to the loss of material attributable to galvanic corrosion, and did not find any deficiency.

3.1.23.4 Conclusions

The staff has reviewed the information in LRA Section A.3.1 and Section B.3.1 of the applicant's October 10, 2000 submittal. On the basis of this review, the staff concludes that the applicant has demonstrated that the galvanic susceptibility inspection program will adequately manage the aging effects attributable to galvanic corrosion of components within the scope of license renewal for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.24 Treated Water Systems Piping Inspections

3.1.24.1 Introduction

The applicant described its treated water systems piping inspection program in LRA Section A.3.2. Supplemental information on the inspection program is further provided in Section B.3.2 of the October 10, 2000, submittal, which provided the applicant's responses to the staff's RAIs. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on structures and components in systems managed by this inspection program will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.24.2 Summary of Technical Information in the Application

The treated water systems piping inspections will provide for condition monitoring via one-time examinations intended to provide objective evidence that existing chemistry control is managing aging in piping that is not examined under another inspection program.

The program will examine a sample population of carbon and stainless steel tubing and piping in the treated water systems. The results of the sample population examinations will be recorded and evaluated, and subsequent examinations will be conducted where evaluation results warrant. If significant degradation is noted, the sample set may be expanded.

The applicant stated that the treated water system piping inspections program will be conducted using techniques appropriate for piping examination and trending. The specific sample population, examination methods and acceptance criteria will be defined in the inspection and trending procedures.

3.1.24.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the treated water systems piping inspection program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The applicant stated that portions of the following systems are included within the scope of this program:

B21 - Nuclear Boiler
B31 - Reactor Recirculation
C11 - Control Rod Drive
C41 - Standby Liquid Control
E21 - Core Spray

E41 - High Pressure Coolant Injection
E51 - Reactor Core Isolation Cooling
N32 - Main Turbine Auxiliaries
P11 - Condensate Storage and Transfer
P42 - Reactor Building Closed Cooling Water
P64 - Primary Containment Chilled Water
R43 - Emergency Diesel Generator Auxiliaries
T23 - Primary Containment
T48 - Containment Atmospheric Control System

The applicant stated that the Unit 1 inspections will be performed on or after August 6, 2009, but before midnight August 6. 2014. The Unit 2 inspections will be performed on or after June 13, 2013, but before midnight June 13, 2018. The staff finds the scope of the program adequate.

Preventive or Mitigative Actions

The applicant stated that the treated water systems piping inspections will be condition monitoring activities which utilize visual inspections to identify unacceptable age-related degradation within the applicable systems. Therefore, there are no preventive or mitigative attributes associated with this program nor did the staff identify a need for such.

Parameters Inspected or Monitored

The applicant stated that these one-time inspections will focus on determining whether there has been loss of material from, or cracking in, Class 1 and non-Class 1 carbon and stainless steels within the reactor water, torus water, demineralized water, closed cooling water, and borated water environments. Appropriate examination methods will be utilized, and inspection locations will be selected, on the basis of engineering judgement. The selection will include areas predicted to be most susceptible to corrosion, erosion-corrosion, erosion, and cracking. The staff finds the parameters inspected acceptable because appropriate examination methods will be employed to detect loss of material and cracking.

Detection of Aging Effects

The applicant stated that a one-time visual inspection of the sample set will be conducted using the best available examination method for the inspected component. Inspections may utilize an examination method similar to that described for VT-1 in ASME Section XI, Paragraph IWA-2210. Where possible and practical, accessible components may be inspected using volumetric examination methods. The staff finds that the detection of aging effects before there is a loss of intended function can be reasonably expected from the inspection program because of the adequate inspection scope, technique, and frequency. Satisfactory operating experience to date also supports this conclusion.

Monitoring and Trending

The applicant stated that periodic monitoring and trending of degradation for inspection locations will be established provided that the one-time inspection results indicate a concern that components may not be able to perform their intended function during the period of extended operation. Failures will be documented in accordance with the Plant Hatch corrective actions program. The staff finds this approach acceptable because it will provide predictability of the extent of degradation so timely corrective or mitigative actions are possible.

Acceptance Criteria

The applicant stated that any unacceptable indication of corrosion will be evaluated by further engineering analysis. Component wall thickness acceptability will be founded on the component design code of record. Cracks identified via visual examinations shall be further inspected via volumetric examinations for evaluation by engineering analysis. Corrective actions, if required, will be addressed through the existing Plant Hatch corrective actions program.

The applicant stated that if components do not meet the acceptance criteria defined in the inspection procedure, they will be evaluated, repaired, or replaced before being returned to service. If a significant number of the initial sample population fail to meet the acceptance criteria, the sample population may be increased. If the applicable acceptance criteria are met for the sample population, expansion of the sample set will not be necessary. The staff finds this approach acceptable because any indication of components not meeting the pre-established acceptance criteria would require the applicant to implement corrective actions.

Operating Experience

The treated water system piping inspections will be a one-time activity. Thus, there is no operating experience directly associated with the treated water system piping inspection. The applicant stated, however, that a review of plant deficiency cards submitted over the past 5-years revealed no significant deficiencies in the in-scope treated water components as a result of age-related degradation.

3.1.24.4 Conclusions

The staff has reviewed the information in LRA Section A.3.2, "Treated Water Systems Piping Inspections," of the LRA and Section B.3.2, "Treated Water Systems Piping Inspections," of the applicant's October 10, 2000 submittal. On the basis of its review, the staff concludes that the applicant has demonstrated that the effects of aging associated with structures and components in systems managed by this program will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.25 Gas Systems Component Inspections

3.1.25.1 Introduction

The applicant described the gas systems components inspections program in LRA Section A.3.3 and Section B.3.3 of the applicant's October 10, 2000 submittal. The program is described under A.3 "New Programs and Activities" of the Final Safety Analysis Report Supplement. The program verifies that age-related degradation is not inhibiting component function in gas-bearing systems within the scope of license renewal. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effects of aging caused by the humid and wetted gas internal environment will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.25.2 Summary of Technical Information in the Application

Section B.3.3 of the applicant's October 10, 2000 submittal describes the gas systems component inspection program, which implements condition monitoring with regard to age-related degradation of components having an internal environments of humid or wetted gas. Loss of material as a result of general corrosion in carbon steel, material property changes, and cracking in low-alloy and stainless steels are also likely to occur because of contaminants such as chlorides and oxygen in the presence of moisture. The applicant has included portions of the following systems within the scope of the gas systems component inspection program: nuclear boiler (comprising the safety relief valve tail pipes to the torus and the associated attached instrumentation valves and piping), CRD, RHR, HPCI, RCIC, sampling, EDG, primary containment, reactor building HVAC, standby gas treatment, primary containment purge and inerting, post-LOCA hydrogen recombiners, outside structure HVAC, fuel oil, and control building HVAC.

The applicant's inspection program is a one-time inspection for condition monitoring that will provide objective evidence that the aging effects predicted for systems with gas as the internal environment are being adequately managed during the period of extended operation. Since loss of material attributable to general corrosion and cracking are associated with the presence of moisture and/or liquid pooling or wet/dry cycling, a sample population of components exposed to such an environmental condition at various temperatures will be inspected. In addition, certain external surfaces in gas-bearing components of the EDG, outside structure HVAC, and control building HVAC will also be included in the sample population. The gas systems component inspection will utilize an examination method similar to that described for VT-1 visual examination of the ASME Code, Section XI, or a volumetric examination for condition monitoring. Any unacceptable indication of corrosion will be evaluated by engineering analysis. The applicant will implement corrective actions through the existing Plant Hatch corrective action program.

3.1.25.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the gas systems piping inspection program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

Gas systems component inspections are one-time inspections of a given sample that are intended to provide objective evidence that the applicable aging effects are being adequately managed. The applicant has stated that it would provide for condition monitoring of the components in the systems with gases as internal environment within the scope of license renewal to determine whether age-related degradation is being managed for the period of extended operation. This determination will be achieved by performing inspections of selected sample populations of gas system components exposed to moisture and/or liquid pooling or wet/dry cycling at various temperatures. The applicant has included portions of the following systems within the scope of the program: nuclear boiler (consisting of the safety relief valve tail pipes to the torus and the attached instrumentation tubing and valves), CRD, RHR, HPCI, RCIC, sampling, EDG, primary containment, reactor building HVAC, standby gas treatment, primary containment purge and inerting, post-LOCA hydrogen recombiners, outside structure HVAC, fuel oil, and control building HVAC. For Unit 1, the inspection will be performed on or after August 6, 2009, but before midnight August 6, 2014. Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018. The staff finds the scope of the program to be acceptable because it covers the systems within license renewal that are susceptible to the aging effects of loss of material and cracking caused by the humid and wetted gas internal environments.

Preventive or Mitigative Actions

There are no preventive or mitigative attributes with this program. The staff did not identify the need for such attributes.

Parameters Inspected or Monitored

The gas systems component inspection will primarily ensure that the component wall thickness has not degraded to such an extent that the function of the component is inhibited. Appropriate examination methods will be utilized and inspection locations will be selected based on engineering judgement. The staff finds the parameters inspected to be acceptable.

Detection of Aging Effects

The inspection will utilize an examination method similar to that described for the VT-1 visual examination of the ASME Code, Section XI, or a volumetric examination for condition monitoring. For those stainless steel components that normally operate at temperatures above 140°F, and that contain wetted gases, volumetric examination may be used as part of the inspections to detect the presence of stress-corrosion cracking. The staff finds the method of detection of aging effects to be acceptable.

Monitoring and Trending

There are no monitoring and trending attributes with this program. The staff did not identify the need for such attributes.

Acceptance Criteria

The acceptance criterion will be based on the applicable sections of the design codes. The wall thickness inspection of unacceptable indications of corrosion will determine the loss of material due to general corrosion and assess the impact of this aging effect on other components in the balance of the plant included in the LRA. The program also requires that corrective actions be taken if any unacceptable indication of corrosion is detected. The staff finds that, as proposed by the applicant, an engineering analysis followed by implementation of specific corrective actions, as specified by the site-controlled corrective action program, will provide an acceptable technical basis for the management of the aging effects in the gas systems components. The staff finds the acceptance criteria to be satisfactory.

Operating Experience

The applicant reviewed records dating back 5 years on the in-scope gas system components, to determine deficiencies that inhibited component function, and did not find any deficiencies. However, because of the possibility of occurrence of this type of age-related degradation, it established a one-time inspection.

3.1.25.4 Conclusions

The staff has reviewed the information in LRA Sections A.3.3 and Section B.3.3 of the applicant's October 10, 2000 submittal. On the basis of this review, the staff concludes that the applicant has demonstrated that the inspection program will adequately manage aging effects associated with the gas system components in a humid and wetted environment for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.26 Condensate Storage Tank Inspection

3.1.26.1 Introduction

The applicant described its CST inspection in LRA Section A.3.4 and Section B.3.4 of the applicant's October 10, 2000 submittal. The staff reviewed these sections to determine whether the applicant has demonstrated that the structures and components managed by the condensate storage tank inspection will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.26.2 Summary of Technical Information in the Application

The applicant stated in the LRA that the CST inspection is a one-time condition monitoring inspection of each CST designed to provide objective evidence that no unacceptable degradation is occurring. The internal surfaces of each CST will be examined to verify that age-related degradation is not occurring. The examination will focus on the standpipes and the connections between aluminum standpipes and galvanized steel flanges, since these locations would be the most susceptible to corrosion. This inspection is intended to validate the adequacy of current demineralized water chemistry controls to manage aging effects.

3.1.26.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the CST inspection program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The CSTs are part of the condensate transfer and storage system. The staff agrees with the applicant that only those CST components required to ensure the availability of 100,000 gallons of water for HPCI and RCIC system operation are within the scope of license renewal and therefore the CST inspection. Therefore, the staff finds the applicant's scope, as indicated in the application, to be appropriate and acceptable.

Preventive or Mitigative Actions

The CST inspection is a condition monitoring activity that utilizes visual inspections to identify unacceptable corrosion within the CSTs. As such, there are no preventive or mitigative attributes associated with this program, nor did the staff identify a need for such.

Parameters Inspected or Monitored

The Plant Hatch Unit 1 CST is fabricated from aluminum alloy structural shapes, pipe, and plate. Nozzle flanges on the Unit 1 CST are fabricated from galvanized carbon steel. Visual inspection on the Unit 1 tank will focus on selected areas associated with the standpipes, associated supports, and nozzles.

The Unit 2 CST is fabricated entirely from austenitic stainless steel. Visual inspection of the Unit 2 tank will focus on selected areas associated with the standpipes, associated supports, and nozzles.

Inspection locations will be determined on the basis of engineering judgement, and will include areas predicted to be most susceptible to corrosion, such as weld heat affected zones and crevices. The applicant indicated that detailed visual inspections are adequate to detect localized corrosion. The applicant also stated that if significant degradation is identified, actions will be taken by the corrective actions program to repair the degraded components and implement any additional inspections that may be warranted. The staff finds that monitoring these parameters are adequate and sufficient to mitigate age-related degradation of the systems and components exposed to CST internal environments.

Detection of Aging Effects

The CST inspection will utilize visual inspection techniques, including lighting and resolution requirements, that are similar to the VT-1 provisions in ASME Code recommendations to detect unacceptable corrosion. The applicant also indicated, as stated above, that if significant degradation is identified, actions will be taken by the corrective actions program to repair the degraded components and implement any additional inspections that may be warranted. The staff finds this approach acceptable.

Monitoring and Trending

The CST inspection is a one-time inspection, designed to validate the adequacy of the demineralized water chemistry control in minimizing corrosion. Therefore, monitoring and trending is not addressed by the applicant for this AMP, nor did the staff identify a need for such.

Acceptance Criteria

Unacceptable indications of corrosion will be further evaluated by engineering analysis, and, if warranted, additional inspections will be performed. Corrective actions, if required, will be addressed through the existing Plant Hatch corrective actions program. The staff finds this approach acceptable.

Operating Experience

The applicant indicated that, from a review of its plant deficiency records over the past 5 years, no age-related deficiencies of in-scope CST surfaces were found. The CST inspection will be a new one-time inspection activity. Therefore, there is no operating experience directly associated with the CST inspection, nor does the staff identify a need for such.

3.1.26.4 Conclusions

The staff has reviewed the information in LRA Section A.3.4 and Section B.3.4 of the applicant's October 10, 2000 submittal. On the basis of its review, the staff concludes that the applicant has demonstrated that the effects of aging associated with structures and components managed by the condensate storage tank inspection will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.27 Passive Component Inspection Activities

3.1.27.1 Introduction

The applicant described the passive component inspection activities in LRA Section A.3.5 and Section B.3.5 of the applicant's October 10, 2000 submittal. The program verifies the effectiveness of preventive or mitigative programs/activities credited for aging management. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effects of aging will be monitored and adequately managed by the passive component inspection activities during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.27.2 Summary of Technical Information in the Application

In LRA Sections A.3.5 and Section B.3.5 of the applicant's October 10 2000 submittal, the applicant described the passive component inspection activities, a new program for condition monitoring inspection to confirm that, for gas-bearing in-scope systems and components, age-related degradation is not inhibiting component function. Loss of material and cracking are the aging effects that will be monitored by the passive component inspection activities. The applicant has included portions of various systems within the scope of the passive components inspection activities, including the nuclear boiler (safety relief valve tail pipes to the torus), control rod drive, residual heat removal (including buried or embedded components), high-pressure coolant injection, reactor core isolation cooling, plant service water (including buried or embedded components), emergency diesel generator (starting air and engine exhaust), primary containment (including the drain lines for the drywell sump discharge), reactor building HVAC, standby gas treatment (including buried or embedded components), primary containment purge and inerting, post-LOCA hydrogen recombiners, outside structure HVAC, fire protection (including buried or embedded components), fuel oil (including buried or embedded components), and control building HVAC (including gaskets).

In LRA Section B.3.5 of the applicant's October 10, 2000 submittal, the applicant stated that the passive component inspection activities will be a set of on-going condition monitoring inspections that will provide objective evidence that the aging effects predicted for in-scope systems are being adequately managed during the period of extended operation. The passive component inspection activities will be invoked when the normally inaccessible surfaces of these components are made available for inspection as a result of maintenance and other activities. The preferred inspection sites will be those locations in the in-scope components where liquid pooling or wet/dry cycling is most likely to occur during normal operation. In addition, certain external surfaces of buried or embedded components of residual heat removal, plant service water, standby gas treatment, fire protection, and fuel oil systems will also be included in the inspection. The passive component inspection activities will utilize an examination method similar to that described for VT-1 visual examination of the ASME Code, Section XI or a volumetric examination for condition monitoring and will identify aging effects before any loss of intended function. Any unacceptable indication of corrosion will be evaluated by engineering analysis. The applicant will implement corrective actions through the existing Plant Hatch corrective action program.

3.1.27.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the passive component inspection activities to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

In response to RAI 3.1.27-1, the applicant listed the systems and components covered by the passive component inspection activities program in Section B.3.5 of the applicant's October 10, 2000 submittal. The program provides for condition monitoring of predominantly gas bearing in-scope systems and components to confirm that age-related degradation is not inhibiting component function. In addition to piping, this activity will include the internal and external surfaces of other passive components, such as valve bodies, ducts, and strainers. Piping and valves between the drywell sump and the liquid radwaste system are also included in the scope of the passive component inspection activities. These pipes and valves serve as part of the primary containment and are not otherwise in-scope for license renewal. The passive component inspection activities will also be used for aging management of gaskets associated with the control building HVAC system. The passive component inspection activities will be invoked when the normally inaccessible surfaces of these components are made available for inspection as a result of maintenance and other activities. The staff finds that the scope of the passive component inspection activities program is acceptable since it includes condition monitoring inspection of all in-scope systems.

Preventive or Mitigative Actions

There are no activities in the passive component inspection activities program for preventive or mitigative actions and the staff did not identify the need for such actions.

Parameters Inspected

In response to RAI 3.1.27-1, the applicant, in Section B.3.5 of the applicant's October 10, 2000 submittal, stated that the passive component inspection activities will primarily ensure that the component wall thickness has not degraded such that component function is inhibited, and for gaskets, the passive component inspection activities will inspect for the presence of cracks or degradation. The staff finds that the inspected parameters will be adequate for identifying loss of material or cracking during the period of extended operation.

Detection of Aging Effects

In LRA Section A.3.5, the applicant stated that the passive component inspection activities will include a baseline examination of the in-scope components, as they become available as a result of normal maintenance activities. The applicant further stated that the inspection will utilize an examination method similar to that described for the VT-1 visual examination of the ASME Code, Section XI, paragraph IWA-2210, to detect corrosion of metallic components and material property changes and cracking of gaskets. The applicant also stated that liquid penetrant (PT) examinations, or other suitable methods dictated by the situation for the affected component, will be used to detect discontinuities open to the component surface. In response to RAI 3.1.27-1, in Section B.3.5, the applicant stated that, where possible and practical, accessible components will be inspected for stress corrosion cracking using volumetric examination methods. The staff finds that the applicants's examination methods will be adequate for detecting loss of material or cracking during the period of extended operation.

Monitoring and Trending

In response to RAI 3.1.27-1, the applicant, in Section B.3.5 of the applicant's October 10, 2000 submittal, stated that the passive component inspection activities program will be designed to collect, report, and trend age-related data. These inspections will assist in the early discovery of aging effects so that timely corrective actions may be taken before the effects inhibit component functions. The staff finds that these monitoring activities are adequate to ensure that corrective actions will be taken before exceeding the acceptance criteria.

Acceptance Criteria

In response to RAI 3.1.27-1, the applicant, in Section B.3.5 of the applicant's October 10, 2000 submittal, stated that any unacceptable indication of corrosion will be evaluated by further engineering analysis and the component wall thickness acceptability will be founded upon the component design code of record. If the gasket exhibits cracking or a change in material properties, then corrective action will be taken through the existing Plant Hatch corrective action program. The staff finds the applicant's acceptance criteria specified above are adequate to ensure that the intended functions of in-scope systems are maintained during the period of extended operation.

Operating Experience

The passive component inspection activities program is a new program; thus, the applicant did not submit plant-specific operating experience. However, in response to RAI 3.1.27-1, the applicant, in Section B.3.5, stated that its review of plant deficiency cards over the past 5-years showed that age-related deficiencies that inhibited component function were not written on components within the scope of passive component inspection activities. The staff finds that operating experience is satisfactorily incorporated into the development of the program.

3.1.27.4 Conclusions

The staff has reviewed the information in LRA Section A.3.5, "Passive Component Inspection Activities," and Section B.3.5 of the applicant's October 10, 2000 submittal. On the basis of this review, the staff concludes that the applicant has demonstrated that the inspection program will provide adequate assurance that in-scope components that are susceptible to aging effects that require management will be inspected for age-related degradation during the period of extended operation.

3.1.28 RHR Heat Exchanger Augmented Inspection and Testing Program

3.1.28.1 Introduction

The applicant described its RHR heat exchanger augmented inspection and testing program in LRA Sections A.3.6, "RHR Heat Exchanger Augmented Inspection and Testing Program," C.2.2.11, "Non-Class 1 Heat Exchanger Evaluation;" and Section B.3.6 of the applicant's October 10, 2000 submittal. The applicant credits this inspection and testing program with managing, in part, aging effects for the RHR heat exchanger components used to remove heat from the reactor vessel or suppression pool. The staff reviewed the application to determine whether the applicant has demonstrated that the RHR heat exchanger augmented inspection and testing program will adequately manage aging effects, in conjunction with other AMPs, during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.28.2 Summary of Technical Information in the Application

In Section A.3.6. of the LRA and Section B.3.6 of the applicant's October 10, 2000 submittal, the applicant describes the RHR heat exchanger augmented inspection and testing program, which manages, in part, the aging effects on carbon steel, stainless steel, and stainless steel-clad carbon steel components exposed to multiple fluid environments. The heat exchanger components managed by this AMP are: tubes; shell; shell nozzles and shell internals; channel assembly (including channel head, water box, and partition plate); tube sheet; and impingement plate.

3.1.28.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the LRA regarding the applicant's demonstration that the RHR heat exchanger augmented inspection and testing program will ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The RHR heat exchanger augmented inspection and testing program is applied to the residual heat removal system heat exchangers, which includes components made of carbon steel, stainless steel, and stainless steel-clad carbon steel. The staff finds this scope to be appropriate and acceptable.

Preventive or Mitigative Actions

The RHR heat exchanger augmented inspection and testing program is designed to mitigate and prevent age-related degradation (flow blockage and loss of thermal performance) through inspection and cleaning of the tubes and channel interior every 3 cycles. These actions prevent buildup of debris inside the tubes and the channel interior. This program satisfies one of the requirements of Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and implements guidance found in SAND 93-7070.UC-523, "Aging Management Guideline for Commercial Nuclear Power Plants - Heat Exchangers (DOE, July 1984)." The operating history shows that, as recently as 1996, leakage was detected in the heat exchangers. The staff had concerns with the leakage identified in 1996, which may have been attributable to vibration-induced cracking. (See Open Item 3.1.28-1, below.)

This program works in conjunction with the pit and diving inspection activities of the PSW and RHRSW Inspection Program. These activities provide for inspection and removal of sediment in the pump suction pit to prevent or minimize flow blockage and loss of material.

The staff finds it appropriate and acceptable to perform heat exchanger tube inspection and cleaning to prevent flow blockage and loss of thermal performance. These actions, in conjunction with the removal of sediment from the suction pit, prevent or minimize flow blockage and loss of material.

Parameters Inspected or Monitored

The LRA states that the RHR heat exchanger augmented inspection and testing program monitors loss of material, flow area reduction, and cracking. Specifically, the LRA states that visual inspections of the internal surfaces of the heat exchanger channel and shell sides are performed at scheduled intervals. In addition, eddy current testing and leak testing are performed at scheduled intervals, and whenever leaks are suspected in tubes and/or tube sheets.

The staff finds that the visual inspections of the heat exchanger channel and shell sides are adequate and appropriate for identifying and removing buildup on the tubes to manage loss of material attributable to general corrosion.

Detection of Aging Effects

The LRA states that the RHR heat exchanger augmented inspection and testing program currently includes visual inspection of the channel side and tube interior every three cycles and inservice inspection of the shell welds and base material at prescribed frequencies. In addition, this program will be augmented to include eddy current testing; visual inspection of the shell side of tube sheets, internals, and impingement plates; and tube and tube sheet leak testing.

The staff finds the methods discussed above appropriate and acceptable since these methods allow for early detection of aging effects.

Monitoring and Trending

The LRA states that the RHR heat exchanger augmented inspection and testing program includes visual inspection of the channel side and tube interior every three cycles. Eddy current testing will be performed at least once per 10-year inspection interval, and when leaks are suspected. Visual inspection of the shell side internals will also be performed once every 10-year inspection interval, where accessible. Tube and tube sheet leak testing will be performed whenever leaks are suspected. However, the bases for these frequencies was not clear (see Open Item 3.1.28-1, below).

Corrective actions are implemented through the corrective actions program and frequency of inspection or testing may be adjusted on the basis of observed trends. The LRA further states that if the monitored parameters fall below the acceptance criteria, repair and/or replacement is performed before returning the component to service, unless an engineering analysis allows continued operation.

On the basis of the information above, and on satisfactory resolution of the open item below, the staff finds that the frequencies of monitoring and trending of the stated parameters are acceptable and appropriate to ensure that the aging effects of components within the scope of the program are managed.

Acceptance Criteria

The LRA states that measured or recordable values of the inspected or monitored parameters shall not fall below the acceptable values for inspection locations and inspection criteria, as defined by the program. The staff requested that the applicant provide additional information with regard to the inspection locations (see Open Item 3.1.28-1, below).

On the basis of the information above, and on satisfactory resolution of the open item below, the staff finds that the acceptance criteria are adequate and appropriate.

Operating Experience

The LRA states that a review of the applicant's condition reporting database revealed one significant event in 1996. At this time, a sample taken from an RHRSW drain valve contained nuclides and, as a result, a helium leak test and eddy current test were performed on the 1E11-B001B RHR heat exchanger. The testing identified possible leakage in nine heat exchanger tubes. Subsequent inspection revealed that, other than the leaking tubes, the tube bundle was in good condition. The nine suspected tubes were plugged. The applicant noted that dents were found at the tube-to-tube support connections of many tubes and may have been indicative of tube vibration. The staff requested that the applicant provide additional information regarding the leakage (see Open Item 3.1.28-1, below).

However, since no exact cause of the tube leakage was identified, and because the damaged areas were minor, no corrective actions were required. Eddy current testing performed on 1E11-B001A during Spring 1999 and on 2E11-B001B during September/October 1998, did not identify any significant deterioration of the tubes. No tube leaks for other RHR heat exchangers occurred during the 5-year period. The staff requested that the applicant provide additional information regarding industry experience and the bases for the inspection schedule for the RHR heat exchangers (see Open Item 3.1.28-1, below).

On the basis of the information above, and on satisfactory resolution of the open item below, the staff concludes that the applicant has adequately considered the plant-specific and industry-wide operating experience related to the RHR heat exchangers in developing the RHR heat exchanger augmented inspection and testing program.

The staff was concerned about cracking in the RHR heat exchangers. The RHR heat exchanger augmented inspection and testing program description was unclear regarding its ability to manage vibration-induced cracking. Therefore, in order to ascertain whether this AMP is adequate to manage vibration-induced cracking, the staff requested that the applicant provide additional information. The requested information is summarized below, and was identified as Open Item 3.1.28-1.

A. The applicant should provide information on the inspection methods, frequencies, acceptance criteria, and associated bases, which are used to detect vibration-induced cracking.

B. The applicant should provide information regarding the leakage identified in 1996, including the analyses conducted that determined the cause of the leakage, the operational changes or component modifications that were instituted in response to the leakage, and additional programs which were developed and credited for managing vibration-induced cracking.

C. The LRA states that measured and recordable values of the inspected or monitored parameters shall not fall below acceptable values for defined inspection locations. The applicant should identify the inspection locations, and the inspection criteria used to determine inspection locations, and their bases.

D. The LRA states that a sample taken from an RHRSW drain valve contained nuclides and as a result, testing was performed on one of the Unit 1 RHR heat exchangers. Dents were found at a number of tube-to-tube support connections and the dents may indicate tube vibration. The applicant should provide the basis for its determination that the dents may have been caused by tube vibration, as opposed to localized corrosion. In addition, the applicant should provide information regarding industry experience related to the bases and criteria of the inspections credited in the RHR heat exchanger augmented inspection and testing program.

By letters dated October 10, 2000 and June 5, 2001, the applicant provided additional information related to the staff's concerns regarding vibration-induced cracking in the RHR heat exchangers. The applicant stated that there is no site or industry operating experience indicating that vibration-induced fatigue cracking is an active mechanism in the RHR heat exchangers. However, the RHR heat exchanger augmented inspection and testing program provides for inspection activities capable of detecting significant tube damage or throughwall leakage that could result from potential vibration-induced damage. The program includes the following:

A. eddy current testing (minimum of 10 percent of the operational tubes) once during each 10 year inspection period to determine the overall condition of the heat exchanger tubes

B. leak testing to quantify leaks in the tubes or tubesheets

C. general visual inspection of the channel side of the heat exchanger every three operating cycles to include visible portions of the tubesheets and tubes

D. general visual inspection of the shell side of the heat exchanger once during the ten year interval to include a representative portion of the tube bundle, tube supports, tube-to-tubesheet interface, and baffles.

The testing frequency is based on a combination of satisfactory results of eddy current tests performed on three heat exchangers and on heat exchanger design margin. Except for one tube in one heat exchanger, the condition of the tubes in all three heat exchangers was found to be free of damage. Also, the heat exchanger transfer surface area is oversized by at least 5 percent to provide sufficient margin if tubes need to be plugged. On the basis of the satisfactory test results, along with the excessive heat transfer capacity, the staff concludes that the equipment will perform its intended function between inspections.

In addition, identification of crack indications by inspection personnel are subject to appropriate engineering evaluation. Areas that are unavailable for inspection due to inability to pass the eddy current probe are noted on the inspection report.

The applicant also provided information regarding the RHR heat exchanger tube leakage identified in 1996. The leakage was suspected due to detection of radionuclides in the RHRSW system. In October 1997, eddy current testing identified nine tubes, including one leaking tube, with significant damage. As a result, all nine tubes were plugged. Although no direct evidence of service-induced damage was identified, a follow-up inspection was recommended. In October 2000, eddy current inspections were performed on all heat exchanger tubes, except those plugged in October 1997. The result of this inspection did not reveal any accelerated degradation indicators and concluded that there was no evidence of any active service-induced degradation.

The staff requested that the applicant provide details regarding the denting found on a number of tube-to-tube support connections. In response, the applicant stated that denting, as referred to in the submitted operating history on the heat exchanger, is indicative of the tube roundness. Though tube dents can be service-induced, the denting is often the result of fabrication flaws from bending or insertion. In addition, based on the October 2000 inspection results, no evidence exists to support localized corrosion or vibration as a significant factor in the tube dents identified.

On the basis of the additional information provided by the applicant, the staff concludes that this new inspection program provides a variety of methods to manage the aging effects associated with the RHR heat exchangers. In addition, the staff finds that the most recent inspection results obtained through the techniques emcompassed by this program support the applicant's conclusion that localized corrosion or vibration is not a significant factor in the tube dents identified.

On the basis of the information provided by the applicant and the staff's evaluation of this information, the staff concludes that the RHR heat exchanger augmented inspection program is adequate and appropriate to manage the aging effects associated with the RHR heat exchangers. Open Item 3.1.28-1 is closed.

3.1.28.4 Conclusions

The staff has reviewed LRA Sections A.3.6, "RHR Heat Exchanger Augmented Inspection and Testing Program;" and C.2.2.11, "Non-Class 1 Heat Exchanger Evaluation," and Section B.3.6 of the applicant's October 10, 2000 submittal. On the basis of its review, the staff has determined that the RHR heat exchanger augmented inspection and testing program activities will adequately manage the aging effects in the RHR heat exchangers, as required by 10 CFR 54.21(a)(3).

3.1.29 Torus Submerged Components Inspection Program

3.1.29.1 Introduction

The applicant described its torus submerged components inspection program in LRA Section A.3.7. The applicant supplemented the description of this AMP in Section B.3.7 of its October 10, 2000 submittal. The applicant credits this inspection program with managing, in part, aging effects for a variety of stainless steel and uncoated steel structures and components that are exposed to the suppression pool environment. The staff reviewed the application to determine whether the applicant has demonstrated that the torus submerged components inspection program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.29.2 Summary of Technical Information in the Application

In LRA Section A.3.7 and Section B.3.7 of the October 10, 2000 submittal, the applicant describes a new aging management program, the torus submerged components inspection program, that manages, in part, aging effects for various structures and components exposed to the suppression pool environment. The affected systems include the high pressure coolant injection, primary containment purge and inerting, nuclear boiler, residual heat removal, core spray, and reactor core isolation cooling. The applicant lists the specific systems, structures, and components in LRA Section 3.2. These structures and components are fabricated from either uncoated carbon steel or stainless steel.

As discussed in LRA Section C.1.2.2, loss of material is an applicable aging effect that may affect both carbon steel and stainless steel components through several corrosion mechanisms. These mechanisms include general corrosion, galvanic corrosion, crevice corrosion, pitting, and MIC. The applicant also considers cracking to be an applicable aging effect that may affect specific stainless steel components as a result of stress corrosion cracking or intergranular attack. The applicant plans to implement the torus submerged components inspection program to provide direct evidence to validate the adequacy of the current suppression pool chemistry controls to mitigate corrosion-related aging effects on specific stainless steel and uncoated carbon steel structures and components. The program will be implemented by midnight August 6, 2014, for Unit 1 and midnight June 13, 2018, for Unit 2.

The suppression pool water (also called "torus water" in the LRA) contained within the torus consists of demineralized water supplied from demineralized water sources (such as the condensate storage tank). The applicant relies on chemistry controls to mitigate aging attributable to corrosion in structures and components exposed to the suppression pool water by controlling the water purity and composition. To supplement this water chemistry program, the applicant will implement the torus submerged components inspection program to provide direct confirmation of the effectiveness of the suppression pool chemistry controls. The applicant will perform visual inspections of accessible stainless steel and uncoated carbon steel components submerged in suppression pool water to detect evidence of loss of material and cracking.

3.1.29.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the torus submerged components inspection program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The applicant stated in LRA Section B.3.7 of the applicant's October 10, 2000 submittal that the scope of this program included structures and components within the nuclear boiler system, residual heat removal system, core spray system, high pressure coolant injection system, reactor core isolation cooling system, and primary containment purge and inerting system. In a letter dated January 31, 2001, the applicant provided additional information regarding the program scope of the torus submerged component inspection program. The initial inspection scope will consist of a sample set of approximately 10 percent of the uncoated components located within the torus. This initial population would be biased toward the areas that are most likely to exhibit corrosion-related degradation. These locations include austenitic stainless steel welds and weld heat affected zones, crevices, areas potentially covered by debris or sludge, and dissimilar metal connections or mating surfaces. The sample set may also include inspection points above the suppression pool water level because the "splash zone" can be a susceptible area. The sample size for subsequent inspections may be revised on the basis of the initial inspection results. The staff considers an initial sample size of 10 percent large enough to provide a reasonable indicator of the general condition of the uncoated structures and components exposed to the suppression pool water environment. In addition, that initial sample will be biased toward those locations that are considered to be most susceptible to localized corrosion. The staff also finds it reasonable to revise subsequent inspections on the basis of initial inspection results. Therefore, the staff finds that the scope of the torus submerged component inspection program is acceptable.

Preventive or Mitigative Actions

There are no preventive or mitigative actions taken as part of this program, and the staff did not identify the need for such actions.

Parameters Inspected or Monitored

The applicant performs visual inspections of specific uncoated carbon and stainless steel structures and components using an examination method similar to VT-1 in ASME Section XI, paragraph IWA-2210, or other suitable method, as dictated by the component configuration. The staff finds visual inspections generally adequate for identifying loss of material. However, the staff finds visual inspections not sensitive enough to detect the early stages of stress corrosion cracking. In LRA Section C.1.2.2.2 the applicant stated that stainless steel components in the HPCI and RCIC turbine discharge headers inside the torus may be susceptible to SCC. The staff requested that the applicant discuss how it manages this aging effect. In it's response to RAI 3.1.29-7, dated October 10, 2000, the applicant stated that the postulation that certain stainless steel components submerged in the suppression pool could experience SCC was very conservative. The staff agrees this is a very conservative assumption given the operating conditions and industry experience to date. In addition, because the function of the HPCI and RCIC turbine discharge headers is to direct exhaust steam into the suppression pool, only advanced and extensive SCC would have an impact on this function. The applicant stated that such significant cracking would be visible to the unaided eye. Given the very unlikely occurrence of SCC or IGA, and the fact that only advanced and extensive SCC or IGA must be present to impact the intended functions of these particular components, the staff finds that the use of VT-1 quality visual examinations is sufficient to detect degradation before it impacts intended functions.

Detection of Aging Effects

To ensure that aging effects are identified before there is a loss of intended function, the staff relies on an adequate program scope, appropriate monitoring of parameters, and appropriate frequency interval. The program scope and parameter monitoring is discussed above. With respect to frequency, the applicant stated that the first inspections will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2. These dates coincide with the end of the current operating period. The staff finds this inspection schedule acceptable. The staff did not identify a need for a specific commitment from the applicant to perform the inspection at a particular time. Recognizing that there are both advantages and disadvantages to performing inspections earlier rather than later in the time period following approval of the renewed license, the staff accepts the applicant's general commitment to complete the inspection before the current operating license expires. The environment is not particularly corrosive, and the system design is robust; on this basis, the staff concludes that system intended functions should remain intact. The applicant will base subsequent inspection frequencies on the engineering evaluation of results from this first inspection. In summary, the staff finds that the torus submerged components inspection program has an adequate inspection scope, uses adequate inspection techniques, and has an adequate inspection schedule. Thus, it may be relied upon to provide reasonable assurance that aging effects will be detected before there is a loss of intended function.

Monitoring and Trending

The applicant stated that results from the baseline inspections will be assessed to determine the scope and the frequency of subsequent inspections. This is acceptable to the staff because it is reasonable to base the need for future inspections on the baseline inspection results.

Acceptance Criteria

The applicant stated in its letter of January 31, 2001, that any indication of corrosion, if judged to be significant by the inspection personnel, will be evaluated by an engineering analysis and, if warranted, additional inspections will be performed. The applicant indicated that inspectors are trained to question acceptability on initial identification of conditions that might warrant further evaluation or correction. Engineering evaluations of component acceptability are consistent with the design code of record, if applicable. The staff finds this approach reasonable and consistent with current industry practice and therefore acceptable.

Operating Experience

The torus submerged components inspection program is a new program; thus, the applicant did not submit plant-specific operating experience. However, industry experience to date supports the attributes of the applicant's program. Thus, the staff finds that operating experience is satisfactorily incorporated into the development of this new program. In addition, the applicant has been performing regular inspections of the torus as part of its protective coatings program and did not identify any significant degradation associated with corrosion.

3.1.29.4 Conclusions

The staff has reviewed the information in LRA Sections A.3.7, "Torus Submerged Components Inspection Program," Section B.3.7 of the applicant's October 10, 2000 submittal, and information provided by letter dated January 31, 2001. On the basis of this information, the staff concludes that the applicant has demonstrated that the torus submerged components inspection program will adequately manage, as a supplement to the suppression pool chemistry controls, aging effects associated with the suppression pool water environment for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.30 Insulated Cables and Connections Aging Management Program

3.1.30.1 Introduction

The applicant described its insulated cables and connections aging management program in a letter dated January 31, 2001. The staff reviewed the letter to determine whether the applicant has demonstrated that the insulated cables and connections aging management program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(c).

3.1.30.2 Summary of Technical Information in the Application

In the letter dated January 31, 2001, the applicant described the insulated cables and connections aging management program as a condition monitoring program designed to confirm that age-related degradation is not inhibiting component function of insulated cables and connections within the scope of license renewal during the period of extended operation. The scope of this program includes accessible and inaccessible insulated cables within the scope of license renewal that are installed in an adverse, localized environment which is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the equipment.

3.1.30.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the insulated cables and connections AMP to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The applicant stated that the program includes accessible and inaccessible insulated cables within the scope of license renewal that are installed in adverse, localized environments in the primary containment structure, reactor building, radwaste building, diesel generator building, turbine building, control building, intake structure, and main stack, which could be subject to applicable aging effects from heat or radiation. This program does not include cables and connections that are in the 10 CFR 50.49 Environmental Qualification program. An adverse, localized environment is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the equipment. An applicable aging effect is an aging effect that, if left unmanaged, could result in the loss of a component's license renewal intended function in the period of extended operation.

On the basis of the information provided in the letter dated January 31, 2001, the staff concludes that the applicant adequately identified the accessible and inaccessible locations for insulated cables and connections within the scope of the aging management program.

Preventive or Mitigative Actions

Accessible insulated cables and connections installed in adverse, localized environments will be visually inspected for jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. Surface anomalies are indications that can be visually monitored to preclude the conductor insulation applicable aging effect.

Inaccessible insulated cables and connections will be tested. The specific type of test performed will be determined before each test.

The staff finds that the different methods used for accessible and inaccessible cables and connections to be sufficient to detect degradation before it impacts intended functions.

Parameters Inspected or Monitored

The applicant stated that change in material properties of the conductor insulation is the applicable aging effect and changes in material properties managed by this program are those caused by severe heat or radiation (conditions that establish an adverse, localized environment). The staff finds the visual examinations and testing to be sufficient to detect changes in material properties before they result in degradation that may impact intended functions.

Detection of Aging Effects

Accessible insulated cables and connections installed in adverse, localized environments will be inspected at least once every 10 years. Inaccessible cables and connections will be tested at least once every 10 years. Samples may be used for this program and if used, an appropriate sample size will be determined before the inspection or test.

Following issuance of a renewed operating license for Plant Hatch, the initial inspections and tests will be completed by the end of the initial license term for each unit (August 6, 2014 for Unit 1 and June 13, 2018 for Unit 2).

The staff finds that the insulated cables and connections aging management program has an adequate inspection schedule regarding the detection of aging effects such that it provides reasonable assurance that the aging effects will be detected before there is a loss of intended function.

Monitoring and Trending

The applicant stated that for accessible and inaccessible insulated cables and connections, the monitoring and trending activities will be defined by the specific type of inspection (visual or testing) to be performed. Plant Hatch procedures require that deficiencies discovered during the performance of the program activities be documented in accordance with the condition reporting process. Chapter 17 of the Unit 2 UFSAR is part of the Plant Hatch QA program and describes the corrective action process.

The staff finds that it is acceptable to base the monitoring and trending activities on the specific type of inspection to be performed on the accessible and inaccessible insulated cables and connections.

Acceptance Criteria

The applicant stated that for accessible insulated cable and connections installed in adverse, localized environments, the acceptance criterion is no unacceptable, visual indications of jacket surface anomalies, which suggest that conductor insulation applicable aging effects may exist, as determined by engineering evaluation. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the license renewal intended function. For inaccessible insulated cables and connections, the acceptance criteria for the test will be defined by the specific type of test to be performed and the specific type cable to be tested.

The staff concludes that the applicant has identified acceptance criteria for accessible insulated cables and connections and will identify acceptance criteria for inaccessible insulated cables and connections (depending on the test and cable chosen) which will support the detection and evaluation of aging effects such that the intended functions for the insulated cables and connections will remain intact.

Corrective Actions

The applicant stated that when the acceptance criteria are not met on accessible and inaccessible insulated cables and connections, further investigation by engineering will be performed. This will be done in order to ensure that the license renewal intended functions will be maintained consistent with the current licensing basis. Corrective actions may include, but are not limited to, testing, shielding or otherwise changing the environment, relocation or replacement. Specific corrective actions will be implemented in accordance with the CAP, which applies to all structures and components within the scope of the insulated cables and connections aging management program. When an unacceptable condition or situation is identified, a determination will be made as to whether this same condition or situation could be applicable to other accessible or inaccessible insulated cables and connections.

The staff finds the CAP and corrective actions as described above and in Chapter 17 of the Unit 2 UFSAR to be acceptable for managing aging for components within the scope of the insulated cables and connections aging management program.

Confirmation Process, Administrative Controls, and Operating Experience

The applicant stated that the confirmation process will ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective. For accessible and inaccessible insulated cables and connections, the confirmation process will be defined by the specific type of inspection or test to be performed.

Administrative controls will provide a formal review and approval process. For accessible and inaccessible insulated cables and connections, the administrative controls process will be identified by the specific type of inspection or test to be performed.

The CAP provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

The staff finds that the CAP satisfies the elements of the confirmation process, the administrative controls, and operating experience such that it provides reasonable assurance that the insulated cables and connections program will adequately manage the effects of aging during the period of extended operation.

3.1.30.4 Conclusions

The staff has reviewed the information in the letter dated January 31, 2001, which described a new program "Insulated Cables and Connections Aging Management Program." On the basis of the information provided in the letter, the staff concludes that the applicant has demonstrated that the insulated cables and connections inspection program (visual and test) will adequately manage the aging effects associated with insulated cables and connections for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.31 Diesel Generator Maintenance Activities

3.1.31.1 Introduction

The applicant described the diesel generator maintenance activities (DGMA) in LRA Section B.1.18 of the applicant's June 5, 2000 submittal. The program is also described in chapter 18.2.18 under "Existing Programs/Activities" of the Final Safety Analysis Report Supplement. The program manages the applicable aging effects for the EDG components that are within scope of license renewal. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effects of aging caused by a variety of environments (demineralized water/antifreeze, raw water, lubricating oil, and moist air) will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.31.2 Summary of Technical Information in the Application

Section B.1.18 of the applicant's June 5, 2001 submittal describes the diesel generator maintenance activities. The DGMA are existing activities that address the aging effects for the diesel generator skid-mounted components within the jacket water cooling, lubricating oil, and scavenging air subsystems within the boundary of the EDG skid. The components are limited to piping, tubing, restricting orifices, valve bodies, pump casings, heat exchangers, heater casings, filter housings, strainer bodies, and strainer elements. The aging effects for these components managed with the DGMA are loss of material, cracking, and loss of heat exchanger performance.

The DGMA include visual inspections, chemical analysis, eddy current testing, and performance based inspections. These activities are performed on the in-scope EDG components at various frequencies depending on the task. Preventative maintenance activities are usually performed during plant refueling outages, and surveillance performance tests are performed at frequencies determined by plant procedures or the technical specifications. These inspections and analyses are designed to identify aging effects before they inhibit system performance by testing for corrosion, wear products, contamination, and deterioration in process variables, e.g. temperature and pressure.

3.1.31.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding diesel generator maintenance activities to ensure that, for the applicable component aging effects, the intended function of the system will be consistent with the CLB for the period of extended operation.

Program Scope

Section B.1.18 of the applicant's June 5, 2001 submittal describes the diesel generator maintenance activities that address the aging effects for the diesel generator skid-mounted components (jacket water cooling, lubricating oil, and scavenging air subsystems). The components are limited to piping, tubing, restricting orifices, valve bodies, pump casings, heat exchangers, heater casings, filter housings, strainer bodies, and strainer elements. The aging effects for these components managed with the DGMA are loss of material, cracking, and loss of heat exchanger performance.

The staff concludes that the applicant adequately identified the EDG components within the scope of the aging management program.

Preventive or Mitigative Actions

The preventative and mitigative DGMA include visual inspections, chemical analyses, eddy current testing, and performance based inspections that are designed to identify aging effects before they inhibit system performance and that ensure that technical specifications are met. Other preventative and mitigative actions include the use of antifreeze with corrosion inhibitors in the jacket water coolant and the option to replace adversely affected components and fluids.

The DGMA are performed at various times depending on the task. Major preventative maintenance activities are currently performed on a cycle corresponding to plant refueling outages. Surveillance performance tests are performed more frequently as prescribed in the Plant Hatch Technical Specification surveillance requirements.

The staff finds the preventative and mitigative diesel generator activities that the applicant described are sufficient to detect degradation before it impacts the intended functions of the EDG system.

Parameters Inspected or Monitored

During the performance of DGMA, the fluid and material condition of the in-scope EDG components are evaluated and inspected. In addition, the performance of the EDG system is monitored.

The jacket water coolant is evaluated for quality and the amount of antifreeze in solution. The lubricating oil is tested for wear products, water, fuel oil, and antifreeze. The chemical properties of the lubricating oil are monitored to ensure that the lubricating oil subsystem can perform to maintain EDG operability. Heat exchanger water boxes, tubes, tube sheets, and sacrificial zinc rods are visually inspected for damage, debris, deposits and corrosion. Eddy current testing is performed on an as-desired basis to evaluate the heat exchanger tube walls for defects and changes in wall thickness. In addition, the performance of the EDG system is monitored for compliance with technical specifications.

The staff finds the chemical analysis, visual examinations, and eddy current testing to be sufficient to detect changes in chemical and material properties before they result in degradation that may impact intended the functions of the EDG system.

Detection of Aging Effects

The DGMA include performance surveillance tests, maintenance activities, chemical analysis, visual inspection, and eddy current testing to detect aging effects in the EDG in-scope components.

During the surveillance tests and preventative maintenance activities, aging effects (cracking, loss of material, and loss of heat exchanger performance) would be identified. In addition, evidence of corrosion or wear products in the chemical analysis of the lubricating oil would identify loss of material. Loss of material would also be identified during the visual inspections and eddy current testing of the heat exchangers. Loss of heat exchanger performance would be detected through the pressure and temperature indications during the performance tests.

The staff finds the methods of detection of aging effects acceptable.

Monitoring and Trending

Chemical analysis data for the lubrication oil is used to detect and trend wear and corrosion products. In addition, inspection and performance data for the heat exchangers is maintained in plant records. The chemical analysis, inspection, and performance data combined with the mitigative performance testing and the preventative maintenance are sufficient to adequately monitor and trend the aging effects in the EDG system.

The staff finds these monitoring and trending activities acceptable.

Acceptance Criteria

The acceptance criteria for performance tests and maintenance activities are listed in specific plant procedures. Performance test acceptance criteria ensure that system operating temperatures, pressures, and expansion tank levels are within acceptable operating ranges. Maintenance activity acceptance criteria correspond to the safety significance of the component inspected. After maintenance, the performance of components must meet the performance test criteria. Industry codes and standards are not applied to the performance of DGMA.

The staff finds the applicant's acceptance criteria specified above are adequate to ensure that the intended functions of in-scope systems are maintained during the period of extended operation.

Operating Experience

The applicant reviewed condition reports and identified several instances where cooler tubes required replacement or repair for excessive loss of material up to and including leakage of the tubes. These corrective actions took place prior to a loss of the system intended function. In addition, performance deficiencies were identified with the AMOT thermostatic flow control valves where the valves leaked past the valve seat or were not otherwise performing their temperature control function adequately. These deficiencies were not the same as those described in NRC Information Notice 91-85, "Potential Failures of Thermostatic Control Valves for Diesel Generator Jacket Cooling Water." Neither a loss of material nor cracking in the valve body caused these performance deficiencies. The valves were replaced or refurbished prior to loss of system intended function.

3.1.31.4 Conclusions

The staff has reviewed the information in LRA Section B.1.18 and Section 18.2.18 of the applicant's June 5, 2000 submittal. On the basis of this review, the staff concludes that the applicant has demonstrated that the inspection program will adequately manage aging effects associated with the emergency diesel generator components in a variety of environments (demineralized water/antifreeze, raw water, lubricating oil, and moist air) for the period of extended operation, as required by 10 CFR 54.21(a)(3).

AGING MANAGEMENT PROGRAMS - CONCLUSION

The staff has reviewed the 30 AMPs included in Sections A, and C of the applicant's LRA and Section C of the applicant's October 10, 2000 submittal. On the basis of its review, the staff concludes that the applicant has demonstrated that the effects of aging associated with structures and components within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended functions will maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2 Reactor Coolant System

3.2.1 Introduction

The applicant described its AMR of the reactor vessel, reactor vessel internals, and reactor coolant systems for license renewal in Sections 3.0, "Aging Management Review Results," and 3.2, "Mechanical Systems," and Appendix C, "Identification of Aging Effects and Aging Management Review Summaries" of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the reactor and RCS will be adequately managed so that the intended function(s) will be maintained in a manner that is consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The environment, material, aging effects, and aging management program for each component in the reactor and reactor coolant systems are documented in Tables 3.2.1-1, 3.2.1-2, and 3.2.2-1 of the LRA. Section C.1 of the LRA contains the evaluation of aging effects requiring management review, and Section C.2 of the LRA contains the aging management reviews for each commodity group. A commodity group is defined as systems or components that were constructed using similar materials and are operating in similar environments.

External environments are defined in Sections C.1.2.8, "Inside"; C.1.2.9, "Outside"; and C.1.2.10, "Buried or Embedded" of the LRA. "Inside" external environments are defined as environments where equipment is sheltered from the weather. "Outside" external environments are defined as environments found outside a structure where equipment would not be sheltered from the weather. "Buried or embedded" external environments are defined as environments beneath the surface of the ground (in some cases with controlled backfill) or embedded in structural concrete. SCs that perform their functions in external environments are, in general, discussed in Sections 3.2, 3.3, 3.4, 3.5, 3.6, and 3.7 of the LRA, and are evaluated in Sections 3.6 and 3.7 of this SER, unless otherwise noted.

3.2.2 Summary of Technical Information in the Application

The RCS consists of the fuel, nuclear boiler system, reactor assembly system, and reactor recirculation system. Each of these systems is described below.

Fuel

Nuclear fuel is provided as a high-integrity assembly of fissionable material, which can be arranged in a critical array. The assembly must be capable of efficiently transferring the generated fission heat to the circulating coolant water, while maintaining structural integrity and keeping the fission products contained.

The external environment of the fuel is a cladding surrounded by water. The fuel cladding experiences the complete range of reactor coolant pressure and temperatures.

Additional information may be found in Section 4.2.1.2 of the Plant Hatch Unit 2 UFSAR.

Nuclear Boiler System

The nuclear boiler system is composed of several components and subsystems that are required to generate steam. Functions provided by the nuclear boiler system include supplying feedwater to the reactor, conducting steam from the reactor, reactor overpressure protection, and some reactor control and/or engineered safety feature functions. The nuclear boiler system is in operation any time the plant is in operation. Most of the major components in the system are part of the reactor coolant pressure boundary.

The system contains the following major components:

- main steam lines (MSLs)
- safety relief valves (SRVs)
- main steam isolation valves (MSIVs)
- feedwater lines
- feedwater line check valves
- instrumentation and controls

Reactor Assembly System

The reactor assembly consists of the RPV and its internal components of the core, shroud, steam separator and dryer assemblies, and jet pumps. Also included in the reactor assembly are the control rods, control rod drive (CRD) housings, and the CRDs. The RPV is a vertical, cylindrical pressure vessel with hemispherical heads of welded construction. The major reactor internal components are the core (fuel, channels, control blades, and instrumentation), the core support structure (including the core shroud, shroud head, separators, top guide, and core support), the steam dryer assembly, and the jet pumps. The reactor internal structural elements are stainless steel or other corrosion-resistant alloys.

The reactor vessel is located inside the primary containment building. The internal environment of the RPV is reactor water, normally at about 533 °F and 1055 psia during plant operation. Water quality is maintained within the specified limits. During plant conditions that require the operation of the shutdown cooling mode of RHR, reactor water can be cooled to approximately 117 °F via the RHR heat exchangers and recirculated back to the reactor through the reactor recirculation system (RRS) piping. During plant shutdown conditions, the water temperature in the RPV can be as low as 70 °F.

Reactor Recirculation System (RRS)

The RRS is one of two core reactivity control systems. The RRS is part of the reactor coolant pressure boundary. Therefore, it also functions to maintain the pressure boundary during normal operation, transients, and accident scenarios to prevent the release of radioactive liquid and gas.

The RRS consists of two parallel loops, each consisting of a recirculation pump, suction and discharge block valves, piping, fittings, flow elements and connections supporting flow, and differential pressure instrumentation. The RRS interfaces with the RHR and RWCU systems to provide a flow-path in support of shutdown cooling, low-pressure coolant injection (LPCI), RWCU, and reactor water level control functions.

More information about this system may be found in Section 4.3 of the Plant Hatch Unit 1 UFSAR and Section 5.5.1 of the Plant Hatch Unit 2 UFSAR.

3.2.2.1 Effects of Aging

The applicant identified the aging effects, component functions, environment, and materials for each component in the reactor assembly system, the nuclear boiler system, and the reactor recirculation system in Tables 3.2.1-1, 3.2.1-2, and 3.2.2-1 of the LRA, respectively.

Since fuel is subject to replacement within a specified time period, according to 10 CFR 54.21(a)(1)(ii), fuel does not require an integrated assessment.

The aging effects for the nuclear boiler system are as follows:

- cracking
- loss of preload
- loss of material
- loss of fracture toughness in cast austenitic stainless steel valve bodies

The aging effects for the reactor assembly system are as follows:

- cracking
- loss of fracture toughness of beltline materials

The aging effects for the reactor recirculation system are as follows:

- cracking
- loss of preload
- loss of material

- loss of fracture toughness of cast austenitic stainless steel pump casing and covers and valve bodies

Survey of Industry Experience

Industry experience was collected from resources such as NRC generic letters, bulletins and information notices; GE service information letters; INPO significant operating event reports; and topical information from various industry working groups. Plant-specific information was derived through plant walkdowns, interviews, and records searches. A list of generic communications considered by the applicant is provided in Section C.1.5 of the LRA.

Survey of Industry Experience for the Nuclear Boiler System

As a result of the review of the condition reporting database, the only age-related deficiency identified was a loss of material due to erosion corrosion of carbon steel components within the Class 1 boundary and exposed to reactor water. NRC Integrated Inspection Report 99-02 concluded that flow-accelerated corrosion (FAC) inspections were conducted and evaluated in accordance with procedures, and the applicant had implemented an effective program to maintain high-energy carbon steel piping systems within acceptable wall thickness limits.

Several instances of leaking Class 1 bolted closures were found during pressure testing conducted prior to drywell closure. These leaks were minor and, in the majority of cases, may be attributed to the thermal effects associated with cooldown of the Class 1 systems for outages. In all cases, these leaks were corrected in accordance with Plant Hatch's implementation of ASME Section XI in-service inspection (ISI) program. Activities performed in accordance with vendor service information letters also contribute to the overall reduction of these leaks. Operating experience with CRD flange bolts indicates numerous instances of pitting and crevice corrosion. These conditions were discovered during ISI program inspections. All fasteners demonstrating evidence of corrosion were replaced.

Several failures of piping components downstream of orifices or other pressure reduction devices within steam systems were noted. In all cases, the cause of the failure was attributed to erosion corrosion related to pressure fluctuations within the system. This experience validates the conclusion that erosion corrosion can occur in areas not identified by the FAC model. The FAC program and treated water systems piping inspections will specifically target these suspect areas for increased inspections in order to minimize future loss of component function. NRC Integrated Inspection Report 99-02 concluded that FAC inspections were conducted and evaluated in accordance with procedures, and the applicant had implemented an effective program to maintain high-energy carbon steel piping systems within acceptable wall thickness limits.

Survey of Industry Experience for the Reactor Assembly System

A review of the operating experience for both Plant Hatch units indicates that there are no outstanding problems. Routine examinations as part of the ISI program and augmented in-vessel inspections, as well as normal maintenance and refueling activities, have not revealed any unanticipated age-related issues for the reactor vessel. There was one instrument penetration that developed a leak attributed to intergranular stress corrosion cracking (IGSCC). The leak was detected as part of normal drywell outage activities and repaired. Corrosion was detected on the mating surface of the Unit 2 RPV head vent flange and repaired. Finally, during a routine maintenance activity, CRD flange bolts were found to have evidence of pitting. All CRD flange bolts were replaced and are inspected routinely upon disassembly.

The operating experience for the Plant Hatch internals was reviewed. Over time, there have been several occurrences of cracking, all of which have been repaired or are currently being monitored in accordance with prescribed procedures and programs. Early in life, IGSCC was detected on the Unit 1 core spray sparger. It was repaired by installing a mechanical clamp. The sparger has been full-flow tested and the clamp examined afterwards with no evidence of degradation. Multiple indications have been detected over the years on the non-safety-related steam dryers. Some have been repaired, while others are monitored. Jet pump inspections have resulted in minor indications associated with set-screw gaps, diffuser-to-adapter welds, riser pipe welds, and tack welds. These are being monitored and reexamined in accordance with the provisions of the BWRVIP. Crack-like indications were also detected in the core shrouds for both units. The applicant conservatively decided to make pre-emptive repairs to eliminate the concern of cracking in shroud circumferential welds. The repaired hardware and vertical welds are periodically examined as specified in the BWRVIP.

Survey of Industry Experience for the Reactor Recirculation System

While no significant failure trends were found within the prior 5 years, the RRS piping has experienced significant age-related degradation due to IGSCC of weld heat-affected zones. Specifically, the Unit 1 piping components have undergone extensive weld overlay repair, and the Unit 2 piping has been replaced with 316NG stainless steel. A primary contributor to these IGSCC failures is dissolved oxygen content in the reactor water. Prior to initiation of hydrogen injection, higher levels of dissolved oxygen produced by radiolysis within the core region created an oxidizing environment conducive to IGSCC. Implementation of hydrogen water chemistry has effectively arrested existing IGSCC-induced cracks, and has prevented new cracks from forming. Therefore, the current reactor water chemistry control in conjunction with other mitigative activities has proven effective in mitigating failures caused by IGSCC.

3.2.2.2 Aging Management Programs

The applicant identified the aging management programs for components in the reactor assembly system, the nuclear boiler system, and the reactor recirculation system in Tables 3.2.1-1, 3.2.1-2 and 3.2.2-1, respectively, of the LRA.

The aging management programs for the nuclear boiler system are as follows:

- torque activities
- protective coatings program
- inservice inspection program
- reactor water chemistry program
- component cyclic or transient limit program
- treated water systems piping inspections
- galvanic susceptibility inspections
- flow-accelerated corrosion program
- demineralized water and condensate storage tank chemistry control program
- suppression pool chemistry control program

- torus submerged components inspection
- gas system components inspections activities
- passive components inspection program

The aging management programs for the reactor assembly system are as follows:

- boiling water reactor vessel internals program
- reactor pressure vessel monitoring program
- reactor water chemistry control program
- component cyclic or thermal transient limit program
- inservice inspection program

The aging management programs for the RRS are as follows:

- reactor water chemistry control program
- component cyclic or transient limit program
- inservice inspection program
- torque activities
- treated water systems piping inspection

The applicant concluded that these programs would manage aging effects in such a way that the intended function of the components would be maintained consistent with the CLB, under all design loading conditions during the period of extended operation.

3.2.3 Staff Evaluation

The applicant described its AMR for the reactor assembly system, nuclear boiler system and RRS in Section 3.2 and Section C of the LRA . The staff reviewed these sections to determine whether the applicant has identified the aging effects for components in these systems and demonstrated that the effects of aging on the components systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). Each commodity group associated with these components was reviewed by the staff to determine the applicability of the aging effects to the system and its components. The staff reviewed each aging management program associated with these components to determine whether the effects of aging will be adequately managed by the program.

3.2.3.1 Effects of Aging

The aging effects for the reactor assembly system, nuclear boiler system, and RRS identified by the applicant are discussed in Section 3.2.2.1 of this SER.

3.2.3.1.1 Effects of Aging on the Reactor Assembly System

The aging effects for the reactor assembly system are as follows:

- cracking
- loss of fracture toughness of beltline materials

Cracking

All components in the reactor assembly system which require aging management, except for the shell and closure head, are subject to cracking. Cracking of the vessel shell and closure head due to fatigue and stress corrosion cracking (SCC) was determined not to be an aging effect requiring management by BWRVIP-74, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines." The applicable fatigue usage factors for the vessel are very low in comparison to other RPV locations. As for SCC of the low-alloy steel vessel shells, BWRVIP-05, "BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations," and BWRVIP-60, "Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals," indicate that even if cracks were to emanate from the vessel cladding, they are not expected to propagate into the low-alloy steel of the reactor vessel. BWRVIP-05 and BWRVIP-60 have been reviewed and approved by the staff.

Loss of Material

The closure studs in the reactor assembly system are not identified as being subject to loss of material or loss of preload. In response to RAI 3.2.3.1-1, the applicant indicated that closure studs are evaluated in BWRVIP-74. BWRVIP-74 does not identify closure studs as being subject to loss of material or loss of preload. The staff agrees with this conclusion because the closure studs are examined during each refueling outage and loss of material or loss of preload has not been identified as an aging effect in the BWR environment.

Although components in the reactor assembly system are in a reactor water environment, the commodity groups in the reactor assembly system are not subject to loss of material. In response to RAI 3.2.3.1-1, the applicant indicates that evaluations performed with regard to vessel components utilized BWRVIP reports that are based on extensive research, testing, and industry experience. Based on the extensive research, testing, and industry experience, the applicant indicated that loss of material is not an aging effect for components in the reactor assembly system. Based on the applicant's response to this RAI, the staff agrees that commodity groups in the reactor assembly system are not susceptible to loss of material.

Void Swelling

According to EPRI technical report TR-107521, void swelling is defined as a gradual increase in dimension of an austenitic stainless steel part as a result of helium bubble nucleation and growth from nuclear transmutation reactions of nickel and boron in the material. EPRI TR-107521 cites sources with conflicting results on predicting the extent of possible void swelling for light-water reactor conditions. One source predicts swelling as great as 14 percent for PWR baffle-former assemblies over a 40-year plant lifetime, whereas results from another source indicate that swelling would be less than 3percent for the most highly irradiated sections of the internals at 60 years. The issue of concern to the staff is the impact of change of dimension due to void swelling on the ability of the reactor vessel internals to perform their intended functions. Swelling of the reactor vessel internals could potentially impact the ability to insert control element assemblies and to maintain proper coolant flow distribution characteristics.

In response to RAI 3.2.3.1-2, the applicant indicated that BWR reactor vessel internals are a greater distance from the fuel than PWR reactor vessel internals and are expected to experience less neutron fluence. In addition, the lowest temperature for which this phenomenon is conjectured to occur is 572 °F, which is a temperature higher than the internals that either Plant Hatch unit will experience. Further, the BWRVIP for BWR internals addressed the key aspects of the internals components and provided inspection criteria, where appropriate, to manage aging. The BWRVIPs that are being implemented at Plant Hatch are adequate to address aging of the internals. Since BWR reactor vessel internals have relatively low neutron fluence and the applicant will perform inspections in accordance with the staff-approved BWRVIP reactor vessel internals programs, the staff concludes that void swelling is not a concern for Plant Hatch.

Neutron and Thermal Embrittlement

Cast austenitic stainless steel (CASS) components in the reactor assembly system may be subject to loss of fracture toughness due to the effects of thermal and neutron embrittlement. CASS components are susceptible to thermal embrittlement if they operate at temperatures greater than 550°F (the threshold that the NRC has established as the point at which thermal aging of CASS components occurs). Also, as indicated in Appendix H to 10 CFR Part 50, neutron irradiation embrittlement becomes significant at neutron fluences greater than 10^{17} n/cm^2 (E>1Mev).

Table 2.3.1-1 of the LRA indicates that jet pump assemblies and fuel supports contain CASS components and are within the scope of license renewal. The Plant Hatch fuel supports support the weight of the fuel assemblies and distribute core flow into the fuel assemblies. Table 2.3.1-1 indicates that the CASS fuel supports have no aging effects requiring management. However, due to the fuel supports' proximity to the core, the staff believes that the CASS fuel supports are likely to be susceptible to neutron embrittlement.

In response to RAI 3.2.3.2-1, the applicant indicated that portions of the jet pump assemblies may experience fluence greater than 10^{17} n/cm^2, but will not experience temperatures exceeding 550°F. On the basis of this information, the staff concludes that jet pump assemblies fabricated from CASS will not be susceptible to thermal embrittlement; but may be susceptible to neutron embrittlement.

The BWRVIP generic AMP for the jet pump assembly components is described in EPRI report TR-108728, "BWRVIP BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines (BWRVIP-41)." The BWRVIP-41 report does not recommend an inspection of CASS jet pump assembly components because CASS components are considered not susceptible to IGSCC. However, the BWRVIP-41 report does not contain any data to indicate the threshold for neutron embrittlement of CASS and does not identify the neutron fluence experienced by the CASS jet pump assembly components. Because the BWRVIP-41 report does not provide data to support its conclusion that inspection of CASS components is not needed, the staff cannot conclude that the loss of fracture toughness resulting from irradiation embrittlement and cracking is not a plausible aging effect requiring aging management. However, the staff notes that irradiation embrittlement of CASS components becomes a concern only if cracks are present in the components. Therefore, if an applicant can show that cracks do not occur in the CASS components, then the staff can conclude that loss of fracture toughness resulting from neutron irradiation embrittlement will not be a significant aging effect.

The staff notes that industry-wide experience shows that cracking has not been observed in CASS jet pump assembly components. Therefore, as part of its safety evaluation of the BWRVIP-41 report, the staff has requested, and the BWRVIP is considering, the inclusion of a baseline inspection in the BWRVIP-41 report to ensure that cracking is not present in the components. Similarly, the staff requested that the applicant propose a one-time inspection of the CASS jet pump assembly components and fuel supports to confirm that the CASS components have not experienced cracking. The inspection should be performed prior to the beginning of the extended period of operation. This was identified as Open Item 3.2.3.1.1-1.

Since the development of this open item, the staff has reconsidered the safety basis for requiring the applicant to perform a one-time inspection of the CASS jet pump assemblies and fuel supports. Since neutron embrittlement becomes a concern only if cracking is present in the components, and because both industry and plant experience have not identified cracking in these components, the staff concludes that there is no demonstrated safety issue regarding neutron embrittlement of the components. Further, the BWRVIP-41 report requires inspections of several jet pump assembly welds, which are more susceptible to cracking than the CASS components and will therefore serve as an indication of the potential need for more extensive inspections later in life. These welds are considered to be more susceptible than the CASS components, which are made in one piece and have no welds, since the BWR environment has the potential to promote IGSCC under normal water chemistry conditions. Therefore, the staff finds that the welds to be inspected in accordance with the BWRVIP-41 report will provide adequate indication if additional inspections may be needed in the future. Therefore, the staff concludes that a one-time inspection of jet pump assemblies and fuel supports is not warranted at this time to support operation for the license renewal term.

The BWRVIP and the NRC's Office of Nuclear Regulatory Research (RES) are considering joint confirmatory research to determine the effects of high levels of neutron fluence on BWR internals. Any future research results would help to determine whether additional inspections, or alternatives to inspections, are warranted. Should research results find that inspections of CASS jet pump assemblies and fuel supports are warranted, the results should be included in a staff-approved revision to the BWRVIP-41 report, or another staff-approved BWRVIP report.

By letter dated June 5, 2001, the applicant committed to continued participation in BWRVIP activities, including the implementation of future BWRVIP documents. Further, the applicant has committed to implementing the guidelines of the BWRVIP-41 report, and any staff-approved revisions to the BWRVIP-41 report.

On the basis that the industry has not observed cracking in CASS jet pump assemblies and fuel supports, the staff has determined that its request for the applicant to perform a one-time inspection to identify cracking in the CASS jet pump assemblies and fuel supports is not warranted at this time.

In addition, the applicant's commitment to implement future staff-approved BWRVIP documents related to aging management of CASS jet pump assembly components and fuel supports, and staff-approved BWRVIP guidelines, provides additional assurance that the aging effects associated with these components will be adequately managed during the period of extended operation.

On the basis of the information discussed above, the staff concludes that the loss of fracture toughness of CASS jet pump assemblies and fuel supports due to the effects of thermal and neutron embrittlement will be adequately managed for the period of extended operation. Open Item 3.2.3.1.1-1 is closed.

3.2.3.1.2 Effects of Aging on the Nuclear Boiler System

The aging effects for the nuclear boiler system are as follows:

- cracking
- loss of preload
- loss of material
- loss of fracture toughness in cast austenitic stainless steel valve bodies

All components, except for bolting in the nuclear boiler system, are subject to cracking. In response to RAI 3.2.3.1-1, the applicant indicated that SCC and fatigue were considered potential mechanisms contributing to cracking of bolting in the nuclear boiler system. However, after considering the causes of SCC and the ASME Code fatigue analysis for bolting, the applicant concluded that these potential mechanisms did not result in aging effects that require aging management. A summary of the applicant's evaluation is provided below.

<u>Stress Corrosion Cracking of Bolting</u>

- Stress corrosion crack initiation and propagation requires that the affected fastener be subjected to water or steam environments containing various contaminants. Significant wetting of fasteners due to mechanical joint leakage is not considered a normal operating condition.

- A common factor in fastener SCC failures involves the usage of lubricants containing MoS_2, or other lubricants that form contaminants that promote SCC when in contact with reactor water. At Plant Hatch, procedural controls prevent the use of these lubricants in safety-related fasteners, thereby further minimizing the potential for SCC to occur.

- The vast majority of bolting failures due to SCC have occurred at PWRs. Boric acid environments are the primary contributors to these SCC failures. Since Plant Hatch is a BWR, bolting does not experience conditions conducive to SCC initiation and propagation.

- Plant Hatch has implemented procedural processes to minimize the potential for excessive applied stresses due to improper preload.

<u>Cracking Resulting from Fatigue of Bolting</u>

Cracking due to fatigue is not considered by the applicant to be an aging effect requiring management for nuclear boiler system fasteners, since the effects of fatigue are generally seen in conjunction with SCC for high-strength fasteners. In addition, pressure bolting for flanged connections in Class 1 systems is designed to meet the requirements of ASME Section III, Paragraph NB-3232.3, which requires that an analysis be performed to evaluate the effect of fatigue (both thermal and vibration induced) on the component.

On the basis of the information provided by the applicant supporting its conclusion that bolting in the nuclear boiler system is not subject to SCC or cracking due to fatigue, the staff concluded that the applicant had not provided sufficient information for the staff to conclude that bolting in the nuclear boiler system is not subject to cracking. The staff was concerned that bolting that is heat treated to a high hardness condition and exposed to a humid environment within containment could be susceptible to SCC. NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," indicates that the bolts' actual yield stress should be less than 150 ksi to preclude SCC. In response to this issue, the staff identified Open Item 3.1.11-1. This open item and its resolution are discussed in Section 3.1.11 of this SER. Specifically, the applicant stated that it has no operating experience to indicate problems with the bolting, nor could they find any problems during an industry survey of operating experience. On the basis of the resolution of this open item, the staff concludes that SCC in high-strength bolting is not applicable to Plant Hatch.

Loss of Material

Class 1 bolting in the nuclear boiler system is identified as not being subject to loss of material. However, all fasteners within the Class 1 boundary are fabricated from low-alloy steels such as SA540, Grade B23 or SA193, Grade B7. The addition of alloy elements prevents general corrosion due to atmospheric contact. Since the normal environment does not include significant wetting, loss of material due to corrosion was not an aging effect requiring management for these fasteners.

All non-stainless steel, non-Class 1 fasteners were evaluated together as a commodity. Many fastener applications at Plant Hatch utilize carbon steel fasteners. The applicant concluded that these fasteners could be potentially susceptible to loss of material. This conclusion was conservatively applied to all non-Class 1 carbon and low-alloy steel fasteners.

The staff agrees that the applicant has identified all components in the nuclear boiler system that are susceptible to loss of material.

3.2.3.1.3 Effects of Aging on the Reactor Recirculation System

The aging effects for the reactor recirculation system are as follows:

- cracking
- loss of preload
- loss of material
- loss of fracture toughness in cast austenitic stainless steel pump casing and covers and valve bodies

On the basis of the review of the information provided in the LRA, the staff concludes that the applicant has adequately identified the plausible aging effects associated with components in the RRS.

The staff concludes that all applicable aging effects have been identified for the reactor assembly system, nuclear boiler system, and RRS, consistent with published literature and industry experience.

3.2.3.2 Aging Management Programs

The aging management programs for the reactor assembly system, nuclear boiler system and RRS are identified in Section 3.2.2.2 of this SER. The aging management programs are reviewed by the staff in the following sections of the SER:

- reactor water chemistry control program, Section 3.1.1
- demineralized water and condensate storage tank chemistry control program, Section 3.1.6
- suppression pool chemistry control program, Section 3.1.7
- inservice inspection program, Section 3.1.9
- torque activities, Section 3.1.11
- component cyclic and transient limit program, Section 3.1.12
- boiling water reactor vessel and internals program, Section 3.1.15
- reactor pressure vessel monitoring program, Section 3.1.17
- flow accelerated corrosion program, Section 3.1.19
- protective coatings program, Section 3.1.20
- galvanic susceptibility inspections, Section 3.1.23
- treated water systems piping inspections, Section 3.1.24
- gas systems component inspections, Section 3.1.25
- passive components inspection activities, Section 3.1.27
- torus submerged components inspection program, Section 3.1.29

3.2.3.2.1 Aging Management Programs for Cast Austenitic Stainless Steel (CASS) Components

This section provides the staff evaluation of the applicant's management of CASS components in the RCS systems.

<u>CASS Components within the Nuclear Boiler System and Reactor Recirculation System</u>

The industry position on CASS is described in the Electric Power Research Institute (EPRI) topical report (TR)-106092, "Evaluation of Thermal Aging Embrittlement for Cast Austenitic Stainless Steel Components in LWR Reactor Coolant Systems," dated September 1997. This report provides a methodology for determining whether CASS components are potentially susceptible to significant thermal embrittlement that could lead to loss of structural integrity if cracks were in the component. The staff's evaluation of EPRI TR-106092 is contained in a letter from C.I. Grimes (NRC) to D.J.

Walters (NEI), dated May 19, 2000. The staff's evaluation indicates that the definition of components in EPRI TR-106092 that are potentially susceptible to significant thermal embrittlement are acceptable, with the exception that: (a) static casting with high molybdenum and greater than 14percent ferrite content would be considered susceptible to significant thermal embrittlement; (b) components with Niobium would be considered susceptible to significant thermal embrittlement; (c) components with greater than 25 percent ferrite would be considered susceptible to significant thermal embrittlement; (d) the calculated ferrite must be determined using Hull's equivalent factors or a methodology producing an equivalent level of accuracy (6 percent deviation between measured and calculated values); and (e) the flaw evaluation procedures in IWB-3640 are applicable to thermally aged CASS with ferrite levels up to 25 percent. Evaluation of CASS components with ferrite levels greater than 25 percent should use fracture toughness data representative of the higher ferrite contents.

The ASME Code ISI for valve bodies equal to or greater than 4 inches nominal pipe size (NPS) and for pump casings requires a volumetric examination of the welds and a visual (VT-3) of the inside surfaces. These examinations should be able to detect cracks in these valve bodies and pump casings before they reach a critical size, and these CASS components need only be examined to ASME Code ISI requirements.

The ASME Code ISI program for valve bodies less than 4 inches NPS requires an outside surface examination, but does not require internal visual or volumetric examination. However, a staff evaluation of CASS valve bodies less than 4 inches NPS indicates that (1) there have been no reported instances of valve body cracking in these small valves, and (2) aged CASS valve bodies, even with extremely low fracture toughness, can withstand very large through-wall cracks. Therefore, valve bodies need only be examined to ASME Code ISI program requirements.

The CASS components outside the reactor vessel are pump casings, valve bodies, and the main steam flow restriction venturi elements. The venturi elements have been determined to not be susceptible to thermal embrittlement based on the grade of CASS and the operating temperature. With the exception of the venturi elements, the applicant will manage cracking and any associated impact of thermal embrittlement should it occur in these components. The aging management will be accomplished through the ISI program, which includes the inspection requirements of Section XI. This meets the position identified in the letter from C.I. Grimes to D.J. Walters dated May 19, 2000. Since the venturi elements are not susceptible to thermal embrittlement and pump casings and valve bodies are inspected to ASME Code ISI requirements, the staff concludes that these components have adequate aging management programs

<u>CASS Components within the Reactor Assembly System</u>

The effect of neutron and thermal embrittlement on CASS components within the reactor assembly system is discussed in Section 3.2.3.1.1 of this SER.

3.2.3.2.2 Aging Management Programs for Vessel Flange Leak Detection (VFLD) Line

The staff was concerned that leakage around the reactor vessel seal rings could accumulate in the VFLD lines, cause an increase in the concentration of contaminants, and cause cracking in the VFLD line. The applicant indicated that the Plant Hatch Unit 1 VFLD line is subject to the AMP for Class 1 stainless steel piping in the nuclear boiler system. Cracking is identified as an aging effect for this commodity group. The ASME Code requires that the welds in Class 1 piping of the size of the VFLD line be inspected using a surface examination, and the pressure boundary to be VT-2-inspected following the system leakage test after each refueling outage.

In the LRA, the applicant indicated that the Plant Hatch Unit 2 VFLD line is stainless steel and contains portions that are classified as Class 1 piping and non-Class 1 piping. The Class 1 piping would be examined to ASME Code Section XI requirements. The non-Class 1 stainless steel piping in the nuclear boiler system will be examined in accordance with the treated water systems piping inspections (TWSPI). The TWSPI provides for a one-time visual inspection of the sample set using the best available examination method. Inspections may utilize an examination similar to that described for VT-1 in the ASME Code.

The inspections implemented as part of the ISI program for Class 1 piping and the inspections implemented as part of the TWSPI for non-Class 1 piping should be able to detect cracking in the VFLD line. On the basis of the information provided by the applicant and summarized above, the staff concludes that the applicant can adequately manage cracking associated with the VFLD.

3.2.3.2.3 Aging Management Programs for ASME Code Class 1 Small-Bore Piping

NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," identified cracking in an unisolable section of emergency core cooling system piping connected to the reactor coolant system. The cause of the cracking was high cycle thermal fatigue created by relatively cold water leaking through a closed valve. In addition, cracks in piping have also been attributed to vibratory fatigue and stress corrosion aging mechanisms.

In response to RAI 3.2.3.2-8, the applicant indicated that the following systems contain ASME Code Class 1 small-bore piping that could be subject to cracking from thermal fatigue or stress corrosion aging mechanisms:

B21 - nuclear boiler system
B31 - RRS
C41 - SLCS
E11 - RHR system
E21 - CS system
E41 - HPCI system
E51 - RCIC system
G31 - RWCU system

Since carbon steel and stainless steel components in these systems are subject to changes in temperature, cracking due to thermal fatigue is an aging effect requiring management. For pipe sizes above 1 inch, the AMP credited for managing aging of these components due to thermal fatigue is the component cyclic or transient limit program. Class 1 piping that is 1 inch and smaller was analyzed using ASME Class 2 methods. For such piping, cracking due to thermal fatigue is addressed as a TLAA in LRA Section 4.2.3, which demonstrates that the analyses remain valid throughout the extended period of operation. Cracking due to vibratory fatigue is not considered an aging effect requiring management since failure of these components due to vibration has been precluded by design.

As described in Section C.1.2.1.2 of the LRA, for SCC to occur in components of the above systems, each of the following three conditions must simultaneously exist:

1. The components must contain susceptible materials (in this case, stainless steel or nickel based alloys).

2. The components must be subject to residual tensile stresses of sufficient magnitude.

3. The components must be subject to a potentially corrosive environment.

All three conditions exist simultaneously in the above systems, so cracking due to IGSCC is an aging effect requiring management.

For these systems, the applicant defines the corrosive environment as high-temperature water where the electrochemical corrosion potential of alloys exposed to the coolant is increased due to the presence of radiolytically produced dissolved oxygen and hydrogen peroxide. Without the appropriate reactor water chemistry controls, this corrosive environment could exist. Therefore, to manage SCC in the above systems, the applicant has credited reactor water chemistry control, coupled with either the ISI program (for 2-inch and larger piping in these systems) or the TWSPI (for piping in these systems that is not included in the ISI program).

The staff was concerned that unanticipated high cycle thermal fatigue resulting from thermal stratification, turbulent penetration, or intergranular stress corrosion could result in cracking of small bore piping. These types of cracking are not evaluated as part of the component cyclic or transient limit program. The ASME Code Class 1 inspection requirements for small-bore piping include a surface examination, but not a volumetric examination. In order to detect cracking resulting from high cycle thermal fatigue or intergranular stress corrosion, a volumetric examination is required. Since the proposed program does not include a volumetric examination, it may not be capable of detecting high cycle thermal fatigue cracks resulting from thermal stratification, turbulent penetration, or intergranular stress corrosion. Therefore, the staff requested that the applicant supplement the existing programs with volumetric examination of the limiting locations in small-bore piping systems, excluding socket welds, which could have thermal stratification or turbulent penetration.

By letter dated September 5, 2001, the applicant committed to including small-bore butt-welded stainless steel piping in the scope of the treated water systems piping inspection (TWSPI) program. TWPSI is a one-time condition monitoring program that provides for visual and volumetric inspections of a sample population intended to detect loss of material and cracking, and confirms the effectiveness of existing chemistry control programs. The staff's review of this aging management program is found in Section 3.1.24 of this SER. On the basis of the applicant's commitment to provide visual and volumetric examinations of the small-bore piping, Open Item 3.2.3.2.3-1 is closed.

3.2.4 Conclusion

The staff has reviewed the information in Sections 3.0 and 3.2, and Section C of the LRA, as well as the applicant's responses to Open Items 3.2.3.1.1-1 and 3.2.3.2.3-1. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the reactor and RCS 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.

3.3 Engineered Safety Features

3.3.1 Introduction

The applicant described its AMR for the engineered safety features (ESF) systems for license renewal in Section 3.2.3, "Engineered Safety Features (ESF) Systems," of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the ESF systems will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2 Summary of Technical Information in the Application

The applicant provided an AMR of eight ESF systems that are considered to be within scope of the license renewal rule. A brief description of each system is provided below.

Core Spray System

The CS system is one of the ECCS that protects the core from overheating in the event of a LOCA. The CS system is a low-pressure system. Actuation of the CS system results from low reactor vessel water level (level 1), high drywell pressure, or manual action. Injection valves to the reactor require a signal from the reactor's low-pressure permissive switches before opening to provide overpressure protection to the system. The pumps take suction from the suppression pool, and spray the top of the fuel assemblies to cool the core and limit the fuel cladding temperature. An alternate suction source for the CS system, the CST, is primarily used to provide RPV makeup and as an injection test supply during outages, and would not normally be used following an accident. The CS system works in conjunction with the LPCI system.

The CS system has two independent loops. Each loop is a 100 percent capacity centrifugal pump driven by an electric motor, a sparger ring in the reactor vessel above the core, piping, valves, and associated controls and instrumentation. To enable the CS system to make a quick startup and to minimize the water hammer possibilities during startup, the CS system discharge lines are always maintained full of water by the jockey pump system, which consists of two centrifugal pumps in each of the two loops. The suction and discharge lines of these pumps are connected through piping and valves to the suction and discharge lines of the CS pumps, respectively. Continuous operation of the jockey pumps ensures that the ECCS discharge lines remain full. The jockey pump system also provides the same feature for the RHR system.

High-Pressure Coolant Injection System

The HPCI system supplies makeup coolant into the reactor vessel from a fully pressurized to a preset depressurized condition. Demineralized makeup water is supplied from the CST or treated water from the suppression pool. The flow rate of the system will maintain the reactor vessel coolant inventory until the reactor pressure drops sufficiently to permit the low-pressure core cooling systems to automatically inject coolant into the vessel.

The HPCI system consists of a turbine-driven pump train, piping, valves, and controls that provide a complete and independent emergency core cooling system. A test line permits functional testing of the system during normal plant operation. A minimum flow bypass line bypasses pump discharge flow to the suppression pool to protect the pump in the event of a stoppage in the main discharge line. Reactor vessel steam is supplied to the turbine. Turbine exhaust steam is then dumped to the suppression pool.

Post-LOCA Hydrogen Recombiner System (Unit 2)

The post-LOCA hydrogen recombiner system ensures that hydrogen does not accumulate within the primary containment in combustible concentrations following a LOCA. This is accomplished by drawing primary containment atmosphere from the drywell, and passing it through the recombiner where the hydrogen reacts with available oxygen to form water vapor. The recombiner discharges to the suppression pool (torus).

The hydrogen recombiner system is part of the combustible gas control system and consists of two identical and independent 100 percent capacity trains. Each train consists of the recombiner skid, the control console, and the power panel. The recombiner skid consists of inlet piping, flow meters, flow control valve, an enclosed blower assembly, heater section, reaction chamber, direct contact water spray connected to the power panel, and the control console through instrument and power cables. Coolant for the water spray gas cooler is provided by the RHR system.

Primary Containment Purge and Inerting System

The primary containment purge and inerting system primarily provides and maintains an inert atmosphere in the primary containment for combustible gas control and fire protection. Plant Technical Specifications require that within 24 hours of reactor operation, the inerting system injects a sufficient amount of gaseous nitrogen into the drywell and torus so that the oxygen concentration falls below 4-percent by volume.

Major equipment for the purge and inerting system include a purge air supply fan, liquid nitrogen storage tank, ambient vaporizer, steam vaporizer, vacuum breaker, valves, piping, controls, and instrumentation. The purge and inerting system provides containment vent paths to the standby gas treatment system, which provides a vent path to the main stack for containment vent and purge operations.

Reactor Core Isolation Cooling System

The RCIC system is a high-pressure coolant makeup system that supports reactor shutdown when the feedwater system is unavailable. The RCIC system provides the capability to maintain the reactor in a hot standby condition for an extended period. Normally, however, the RCIC system is used until the reactor pressure is sufficiently reduced to permit use of the shutdown cooling mode of the RHR system.

The RCIC system consists of a turbine-driven pump, piping and valves, and the instrumentation necessary to maintain the water level in the reactor vessel above the top of the active fuel should the reactor vessel be isolated from normal feedwater flow. Also included in the design of the RCIC system is a barometric condenser, and vacuum and condensate pumps to prevent steam from leaking into the environment.

Residual Heat Removal System

The RHR system is composed of several components and subsystems that are required to maintain the following functions:

- Restore and maintain reactor vessel water level after a LOCA.
- Limit temperature and pressure inside the containment after a LOCA.
- Remove heat from the suppression pool water.
- Remove decay and residual heat from the reactor core to achieve and maintain a cold shutdown condition.

The RHR system consists of four pumps and two heat exchangers divided into two loops of two pumps and one heat exchanger each, plus the associated instruments, valves, and piping. The RHR pumps take suction from the suppression pool or the reactor coolant recirculation loop. The pumps discharge into the recirculation loop, the suppression pool, the containment spray headers, and the spent-fuel pool cooling and cleanup system, depending upon the desired mode of system operation. The RHR system interfaces with the recirculation system to provide a flow-path in support of shutdown cooling and LPCI. The RHR system is part of the reactor coolant pressure boundary; therefore, it also maintains the pressure boundary during normal operation, transients, and accident scenarios to prevent the release of radioactive liquid and gas.

The RHR system is cooled through the heat exchangers by the RHRSW system, which takes suction from the Altamaha River. There are four RHRSW pumps per unit. The RHRSW system also serves as a standby coolant supply system by providing a means of injecting makeup water from the river to the RHR system to keep the core covered during an extreme emergency.

Standby Gas Treatment System

The SGTS is an ESF system for ventilation and cleanup of the primary and secondary containment during certain postulated DBAs. As such, the SGTS meets the design, quality assurance, redundancy, energy source, and instrumentation requirements for ESF systems. The SGTS is also used as a normal means of venting the drywell.

The major components of the SGTS are redundant filter trains, control valves, backdraft dampers, fans, and control instrumentation. Each of the filtration assemblies and their respective components are designed for 100 percent-capacity operation.

Standby Liquid Control System

The SLCS ensures reactor shutdown, from full power operation to cold subcritical, by mixing a neutron absorber with the primary reactor coolant. The system is designed for the condition when an insufficient number of control rods can be inserted from the full-power setting. The neutron absorber is injected within the core zone in sufficient quantity to provide a sufficient margin for leakage or imperfect mixing. The system is not a scram or a backup scram system for the reactor; rather, it is an independent backup system for the CRD system.

The SLCS is located in the reactor building, and consists of a low-temperature sodium pentaborate solution storage tank; a test tank; a pair of full-capacity positive displacement pumps; two explosive actuated shear plug valves; two accumulators; the poison sparger; and the necessary piping, valves, and instrumentation. The SLCS is manually initiated from the control room by use of a three-position key-lock switch.

3.3.2.1 Aging Effects and Aging Management Programs

The applicant presented the aging effects and aging management programs for the subsystems in the ESF system in Sections C.1 and C.2 of the LRA. The applicable internal environments for the components in the ESF systems are: reactor water, demineralized water, suppression pool, borated water, river water, dry compressed gas, humid or wetted gases, and inside environments. External environments are defined in Sections C.1.2.8, "Inside;" C.1.2.9, "Outside;" and C.1.2.10, "Buried or Embedded" of the LRA. "Inside" external environments are defined as environments where equipment is sheltered from the weather. "Outside" external environments are defined as environments found outside a structure where equipment would not be sheltered from the weather. "Buried or embedded" external environments are defined as environments beneath the surface of the ground (in some cases with controlled backfill) or embedded in structural concrete.

Cracking due to thermal fatigue is an applicable aging effect for several ESF components. The applicant states that all non-Class 1 components are enveloped by a TLAA that adequately addresses this aging effect without regard to the individual component or system conditions. This analysis is presented in Section 4.2.3 of the application. The staff's evaluation of this analysis is presented in 4.2 of this SER.

<u>Reactor Water Environment</u>

Section C.2.2.1 of the LRA, discusses the aging management of various materials in this commodity group, including carbon steel and stainless steel. The reactor water is used in the power cycle, and is demineralized and maintained with low levels of impurities (halogens and sulfates) and minimal dissolved oxygen concentrations.

Based on Tables 3.2.3-4 and 3.2.3-5 of the LRA, the HPCI system and the RCIC system contain piping, restricting orifices, valve bodies, and steam traps manufactured from carbon or stainless steels, and are exposed to the reactor water environment under normal conditions.

The aging effects of carbon steel components exposed to the reactor water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- reactor water chemistry control
- flow accelerated corrosion program
- treated water systems piping inspections
- galvanic susceptibility inspections

The aging effects of stainless steel components exposed to the reactor water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- reactor water chemistry control
- treated water systems piping inspections

<u>Demineralized Water Environment</u>

Section C.2.2.2 of the LRA, discusses the aging management of various materials in this commodity group, including carbon steel and stainless steel. The demineralized water is processed on site and stored in demineralized water storage tanks and condensate storage tanks. Detrimental impurities and conductivity are maintained at low levels, but dissolved oxygen concentrations are neither controlled nor monitored.

Based on Tables 3.2.3-4 and 3.2.3-5 of the LRA, the HPCI system and the RCIC system contain piping, pump casings, restricting orifices, valve bodies, and thermowells manufactured from these materials and exposed to the demineralized water environment under normal conditions.

The aging effects of carbon steel components exposed to the demineralized water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- demineralized water and condensate storage tank chemistry control
- treated water systems piping inspections
- galvanic susceptibility inspections

The aging effects of stainless steel components exposed to the demineralized water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- demineralized water and condensate storage tank chemistry Control
- treated water systems piping inspections

<u>Suppression Pool Environment</u>

Section C.2.2.3 of the LRA discusses the aging management of various materials in this commodity group, including carbon steel, cast austenitic stainless steel, and stainless steel. The suppression pool water is contained within the torus, and consists of demineralized water supplied from sources such as the condensate storage tanks. Detrimental impurities and conductivity are maintained at low levels, although allowable levels are well above those acceptable for demineralized water. Dissolved oxygen concentrations are neither controlled nor monitored.

Based on Tables 3.2.3-2, 3.2.3-3, 3.2.3-4, 3.2.3-5, and 3.2.3-7 of the LRA, the RHR system, the CS system, the HPCI system, the RCIC system, and the primary containment purge and inerting system contain conductivity elements, piping, pump casings, restricting orifices, strainers, thermowells, and valve bodies that are manufactured from these materials and are exposed to the suppression pool water environment under normal conditions.

The aging effects of carbon steel components exposed to the suppression pool water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- suppression pool chemistry control

- protective coatings program (external surfaces of submerged carbon steel components in suppression pool)

- torus submerged components inspection program

- treated water systems piping inspections

- galvanic susceptibility inspections

The aging effects of stainless steel and cast austenitic stainless steel components exposed to the suppression pool water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- suppression pool chemistry control
- torus submerged components inspection program
- treated water systems piping inspections

Borated Water Environment

Section C.2.2.4 of the LRA, discusses the aging management of various materials in this commodity group, including carbon steel and stainless steel. The borated water is contained within the SLCS and consists of demineralized water supplied from the demineralized water storage tank, with approximately 10 percent by weight sodium pentaborate added. Concentrations of anion species are quite low, thereby minimizing significant corrosion within the system. The SLCS storage tank is not regularly monitored for detrimental impurities.

Based on Table 3.2.3-1 of the LRA, the SLCS contains piping, pump accumulators, pump casings, tanks, thermowells, and valve bodies that are manufactured from these materials and are exposed to the borated water environment under normal conditions.

The aging effects of carbon steel components exposed to the borated water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- protective coatings program
- demineralized water and condensate storage tank chemistry control

The aging effects of stainless steel components exposed to the borated water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- demineralized water and condensate storage tank chemistry control
- treated water systems piping inspections

River (Raw) Water Environment

Section C.2.2.6 of the LRA, discusses the aging management of various materials in this commodity group, including carbon steel, stainless steel, cast austenitic stainless steel, and copper alloys. River water is supplied from the Altamaha River via a roughly screened intake structure. It is assumed that some debris, silt, and macroorganisms may be introduced into the plant service water (PSW) and RHR service water (RHRSW) systems.

Based on Table 3.2.3-2 of the LRA, the RHRSW system contains piping, pump discharge heads, pump casings, restricting orifices, strainer bodies, tubing, and valve bodies that are manufactured from these materials and exposed to the river water environment under normal conditions.

The aging effects of carbon steel components exposed to the river water environment are loss of material, cracking, and flow blockage. The management of these aging effects is achieved through the following aging management programs:

- PSW and RHRSW chemistry control
- PSW and RHRSW inspection program
- galvanic susceptibility inspections

The aging effects of stainless steel, cast austenitic stainless steel, and copper alloy components exposed to the river water environment are loss of material, cracking, and flow blockage. The management of these aging effects is achieved through the following aging management programs:

- PSW and RHRSW chemistry control
- PSW and RHRSW inspection program

Dry Compressed Gas Environment

Section C.2.2.8 of the LRA discusses the aging management of various materials in this commodity group, including carbon steel and stainless steel. The dried gas environment includes any process gas including, but not limited to air, nitrogen (including cyrogenic), carbon dioxide, hydrogen, helium, and fluorocarbons supplied from a tank or bottle or is filtered and desicated to remove moisture prior to entering the system.

Based on Tables 3.2.3-4 and 3.2.3-7 of the LRA, the HPCI system, and the primary containment purge and inerting system contain flexible connectors, piping, pressure buildup coils, rupture discs, storage tanks, valve bodies, and vaporizers that are manufactured from these materials and exposed to the dry compressed gas environment under normal conditions.

The aging effect of all the above carbon steel and stainless steel components exposed to the dry compressed gas environment is cracking. The management of this aging effect is achieved through the TLAA on thermal fatigue, discussed in Section 4.2 of the LRA and reviewed by the staff in Section 4.2 of this SER.

Humid and Wetted Gas Environment

Section C.2.2.9 of the LRA, discusses the aging management of various materials in this commodity group, including carbon steel, gray cast iron, stainless steel, copper alloy, galvanized carbon steel, and aluminum. The non-dried gases included in the humid and wetted environment is air (nitrogen in the case of the inerted drywell) containing humidity or significant moisture. These gases are assumed to contain sufficient moisture and oxygen to enable pooling of the liquid at low or especially cool locations and promote corrosion.

Based on Tables 3.2.3-2, 3.2.3-4, 3.2.3-5, 3.2.3-6, 3.2.3-7, and 3.2.3-8 of the LRA, the RHR system, the HPCI system, the RCIC system, the SGTS, the primary containment purge and inerting system, and the post-LOCA hydrogen recombiner system (Unit 2 only) contain piping, turbine casing, restricting orifice, valve bodies, steam trap, strainer-steam exhaust, filter housing, rupture disc, thermowell, flex hose, and nitrogen tank jacket that are manufactured from these materials and exposed to the humid and wetted gas environment under normal conditions.

The aging effect of carbon steel and gray cast iron components exposed to the wetted gas environment is loss of material. The management of this aging effect is achieved through the following aging management programs:

- gas systems component inspections
- passive component inspection activities

The aging effect of stainless steel, copper, and copper alloy components exposed to the wetted gas environment is loss of material. The management of this aging effect is achieved through the following aging management programs:

- gas systems component inspections
- passive component inspection activities

The other aging effect of carbon steel and stainless steel components exposed to the wetted gas environment is cracking. Two aging mechanisms can lead to cracking: stress corrosion cracking in stainless steels (where the normal operating temperature exceeds 140 °F) and thermal fatigue. Stress corrosion cracking will also be managed through the gas systems component inspections and the passive components inspection activities. The management of cracking due to thermal fatigue is achieved through the TLAA on thermal fatigue, discussed in Section 4.2 of the LRA and reviewed by the staff in Section 4.2 of this SER.

<u>Inside Environment</u>

Section C.2.4.1 of the LRA, discusses the aging management of various materials in this commodity group, including carbon steel, cast iron, stainless steel, copper alloy, galvanized carbon steel, and cast iron. The normal inside environment is an environment where minimal wetting and wet/dry cycling is expected to occur.

Based on Tables 3.2.3-2, 3.2.3-4, and 3.2.3-5 of the LRA, the RHR system, the HPCI system, and the RCIC system contain pump sub bases and pump base plates that are manufactured from carbon steel and exposed to the inside environment.

The aging effect of the carbon steel components exposed to the inside environment is loss of material. The management of this aging effect is achieved through the protective coatings aging management program.

Bolting Materials

Section C.2.2.10 of the LRA, discusses only the carbon steel and stainless steel bolting pertaining to piping connections that are exposed to inside and outside environments.

Based on Tables 3.2.3-1 through 3.2.3-5, 3.2.3-7, and 3.2.3-8 of the LRA, all ESF systems, contain these bolts which are subject to an AMR.

The aging effects of carbon steel bolts exposed to an inside or outside environment are loss of material and loss of preload. The management of these aging effects is achieved through the following aging management programs:

- torque activities
- protective coatings program

The aging effect of stainless steel bolts exposed to an inside or outside environment is loss of preload. The management of this aging effect is achieved through the torque activities.

Residual Heat Removal Heat Exchangers

Section C.2.2.11 of the LRA discusses the residual heat removal system heat exchangers, which are fabricated from several different materials and are exposed to multiple fluid environments.

Based on Table 3.2.3-2 of the LRA, the RHR heat exchangers contain several components that are subject to an AMR, including stainless steel heat exchanger tubes; carbon steel shell, shell nozzles, and shell internals; carbon steel channel assembly; carbon steel tube sheet with stainless steel cladding on raw water surfaces only; and stainless steel impingement plates.

The aging effects associated with these components are cracking, loss of material, and loss of heat exchanger performance. These aging effects are managed through the following programs:

- RHR heat exchanger augmented inspection and testing program
- Inservice inspection program
- suppression pool chemistry control
- plant service water and RHR service water chemistry control

3.3.3 Staff Evaluation

The applicant described its AMR of the SLCS, RHR system, CS system, HPCI system, RCIC system, SGTS, primary containment purge and inerting system, and post-LOCA hydrogen recombiners system (Unit 2 only), collectively called the ESF systems, in Section 3.2.3 and Sections A, B, and C of the LRA. In response to the staff's concerns regarding the aging management programs, the applicant provided Section B, "Response to Requests for Additional Information Related to Aging Management Programs Dated July 14, 2000 and July 28, 2000." The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the ESF systems will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff's evaluation of the applicable aging effects for each ESF system and the aging management programs is presented in a manner similar to that provided in the LRA. The aging effects are discussed based on the environment, with a list of systems in which the environment is found. The aging management programs credited with managing these aging effects are also discussed. The aging effects for ESF components and the credited aging management programs discussed below are based on the stated internal environment, unless otherwise noted. Structures and components which perform their functions in external environments are, in general, discussed in Sections 3.2 through 3.7 of the LRA, and are evaluated in Sections 3.6 and 3.7 of this SER, unless otherwise noted.

By letter dated June 5, 2001, the applicant provided additional information to address Open Item 2.3.3.2-1 regarding the post-LOCA hydrogen recombiner system. The applicant provided additional information for the hydrogen recombiner skid components, consistent with NRC guidance on the evaluation of skid-mounted assemblies. The applicant added the following mechanical components to the list provided in Table 2.3.3-8 of the LRA: carbon steel blower casing, carbon and stainless steel instrumentation, stainless steel piping, stainless steel reaction chamber, carbon steel water separator and stainless steel water spray cooler. In addition to listing these mechanical components in the scoping section of the LRA, the applicant provided supplementary information for Table 3.2.3-8, "Aging Effects Requiring Management for Components Supporting Post LOCA Hydrogen Recombiner System [T49] Intended Functions and Their Component Functions (Unit 2 only)."

The applicant stated that for the carbon and stainless steel instrumentation, piping, reaction chamber and water spray cooler in a wetted gas environment, the applicable aging effects are cracking due to thermal fatigue and loss of material. The gas systems component inspection program is credited for managing these aging effects. For the carbon steel blower casing and carbon steel water separator in a wetted gas environment, the applicant listed cracking due to thermal fatigue and loss of material as applicable aging effects. The passive component inspection activities program and the gas systems component inspection program are credited for managing these aging effects. The staff has reviewed the information discussed in the applicant's open item response and concludes that the applicable aging effects and aging management programs listed for the additional components are appropriate and acceptable. The programs credited for managing the aging effects are evaluated in Sections 3.1.25 (gas systems component inspection program) and 3.1.27 (passive component inspection activities program) of the SER and is consistent with components made of similar materials exposed to the wetted gas environment.

By letter dated June 5, 2001, the applicant also provided additional information to address Open Item 2.3.3.2-2 regarding the SGTS. The applicant provided additional information related to the identification and management of aging effects for those fans, dampers, and heating and cooling coil housings which are within the scope of license renewal. The applicant revised the first sentence of the second paragraph in LRA Section 2.3.3.6, "Standby Gas Treatment System [T46]," to state, "The major components of the SGTS include redundant filter trains, control valves, air-operated and backdraft dampers, fans and control instrumentation." In addition, the applicant added the carbon steel damper (frame only) and carbon steel fan housing to LRA Table 2.3.3-6 and Table 3.2.3-6, "Aging Effects Requiring Management for Components Supporting Standby Gas Treatment System [T46] Intended Functions and Their Component Functions."

The applicant stated that for the carbon steel damper (frame only) and fan housing exposed to an air environment, the applicable aging effects are cracking and loss of material. The passive component inspection activities program and the gas systems component inspection program are credited for managing these aging effects. The staff has reviewed the information discussed in the applicant's open item response and concludes that the applicable aging effects and aging management programs listed for the additional components are appropriate and acceptable. The programs credited for managing the aging effects are evaluated in Sections 3.1.25 (gas systems component inspection program) and 3.1.27 (passive component inspection activities program) of the SER and is consistent with components made of similar materials exposed to the wetted gas environment.

3.3.3.1 Aging Effects

Reactor Water Environment

The applicant lists carbon steel and stainless steel components exposed to the reactor water environment in the HPCI system and the RCIC system. The aging effects of carbon steel components exposed to the reactor water environment are loss of material due to general corrosion, galvanic corrosion, microbiologically influenced corrosion (MIC), crevice corrosion, pitting, and erosion corrosion; and cracking due to thermal fatigue. The aging effects of stainless steel components exposed to the reactor water environment are loss of material due to crevice corrosion, pitting, and MIC; and cracking due to SCC, IGA, and thermal fatigue.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in a reactor water environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

Demineralized Water Environment

The applicant lists carbon steel and stainless steel components that are exposed to the demineralized water environment in the HPCI system and the RCIC system. The aging effects of carbon steel components exposed to the demineralized water environment are loss of material due to general corrosion, galvanic corrosion, MIC, crevice corrosion, pitting, and erosion corrosion; and cracking due to thermal fatigue. The aging effects of stainless steel components exposed to the demineralized water environment are loss of material due to crevice corrosion, pitting, and MIC; and cracking due to thermal fatigue.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in a demineralized water environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

Suppression Pool Environment

The applicant lists carbon steel, stainless steel, and cast austenitic stainless steel components exposed to the suppression pool environment in the RHR system, the CS system, the HPCI system, the RCIC system, and the primary containment purge and inerting system. The aging effects of carbon steel components exposed to the suppression pool water environment are loss of material due to general corrosion, galvanic corrosion, MIC, crevice corrosion, pitting, and erosion corrosion; and cracking due to thermal fatigue. The aging effects of stainless steel components exposed to the suppression pool water environment are loss of material due to crevice corrosion, pitting, and MIC; and cracking due to thermal fatigue.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in a suppression pool environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

Borated Water Environment

The applicant lists carbon steel and stainless steel components exposed to the borated water environment in the SLCS. The aging effects of carbon steel components exposed to the borated water environment are loss of material due to general corrosion, galvanic corrosion, MIC, crevice corrosion, and pitting; and cracking due to thermal fatigue. The aging effects of stainless steel components exposed to the borated water environment are loss of material due to crevice corrosion, pitting, and MIC; and cracking due to thermal fatigue.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in a borated water environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

River Water Environment

The applicant lists carbon steel, stainless steel, stainless steel-clad carbon steel, cast austenitic stainless steel, and copper alloy components exposed to river water in the RHRSW system. The aging effects of carbon steel components exposed to the river water environment are loss of material due to general corrosion, galvanic corrosion, MIC, crevice corrosion, fouling, erosion-corrosion and pitting; cracking due to thermal fatigue; and flow blockage due to fouling. The aging effects of stainless steel components exposed to the river water environment are loss of material due to crevice corrosion, pitting, MIC, and fouling; cracking due to thermal fatigue; and flow blockage due to fouling. The aging effects of copper alloy components exposed to the river water environment are loss of material due to selective leaching, galvanic corrosion, MIC, fouling and erosion corrosion; cracking due to thermal fatigue; and flow blockage due to fouling.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in a river water environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

Dry Compressed Gas Environment

The applicant lists carbon steel and stainless steel components exposed to the dry compressed gas environment in the HPCI system and the primary containment purge and inerting system. The aging effect of carbon steel and stainless steel components exposed to the dry compressed gas environment is cracking due to thermal fatigue.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in a dry compressed gas environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

Humid and Wetted Gas Environment

The applicant lists carbon steel, cast iron, stainless steel, copper alloy, and galvanized carbon steel components exposed to the nondried (wetted) gases in the RHR system, the HPCI system, the RCIC system, the SGTS, the primary containment purge and inerting system, and the post-LOCA hydrogen recombiner system (Unit 2 only). The aging effects for carbon steel components exposed to the wetted gas environment are loss of material due to general corrosion, selective leaching, pitting, crevice corrosion, galvanic corrosion, and MIC; and cracking due to thermal fatigue. The aging effects of stainless steel components exposed to the wetted gas environment are loss of material due to pitting, crevice corrosion, and MIC; and cracking due to thermal fatigue, SCC, and IGA. The aging effects for copper alloy components exposed to a wetted gas environment are loss of material due to selective leaching, pitting, crevice corrosion, MIC, and galvanic corrosion, and cracking due to thermal fatigue. The aging effects for galvanized carbon steel exposed to the wetted gas environment are loss of material due to general corrosion, galvanic corrosion, crevice corrosion, pitting, and MIC, and cracking due to thermal fatigue.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in a humid and wetted gas environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

Inside Environment

The applicant lists carbon steel components exposed to a normal inside environment in the RHR system, the HPCI system, and the RCIC system. The aging effect of carbon steel components exposed to the inside environment is loss of material due to general corrosion in areas where the external surface is less than 200°F.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in an inside environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

Bolting Materials

The applicant lists carbon steel and stainless steel bolting associated with piping connections that are exposed to inside and outside environments at Plant Hatch. These components are found in the SLCS, the RHR system, the CS system, the HPCI system, the RCIC system, the primary containment purge and inerting system, and the post-LOCA hydrogen recombiner system (Unit 2 only). The aging effects of carbon steel bolts exposed to an inside or outside environment are loss of material due to general corrosion in the inside environment, and general corrosion, MIC, crevice corrosion, and pitting in the outside environment; and loss of preload due to embedment, gasket creep, thermal effects, and self-loosening. The aging effect of stainless steel bolts exposed to an inside or outside environment is loss of preload due to embedment, gasket creep, thermal effects, and self-loosening.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on bolting materials in various environments, the staff concludes that the applicant has adequately identified the applicable aging effects.

Residual Heat Removal Heat Exchangers

The applicant lists different components fabricated from several different materials that are exposed to multiple fluid environments. The aging effects associated with these components are cracking due to SCC and IGA of stainless steel components and vibration-induced fatigue; loss of material due to general corrosion, galvanic corrosion, crevice corrosion, pitting, MIC, and fouling; and loss of heat exchanger performance due to corrosion product buildup, silting, and macroorganism intrusion.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on RHR heat exchanger materials in various environments, the staff concludes that the applicant has adequately identified the applicable aging effects.

Summary of the Review of Aging Effects Operating Experience

The staff has reviewed the information provided by the applicant regarding plant-specific, as well as industry-wide experience to support its identification of applicable aging effects. This included the description of the internal and external environments, and materials of fabrication for these systems. On the basis of this review, the staff concludes that the applicant has included aging effects that are consistent with published literature and industry experience and, thus, are acceptable to the staff.

3.3.3.2 Aging Management Programs

Reactor Water Chemistry Control

The reactor water chemistry control program is an existing program at Plant Hatch that includes regular sampling, results analysis, and when applicable, chemistry modification of reactor water. In addition, the collected data are regularly trended, tracked, and evaluated. This program is credited for managing the aging effects of components in the HPCI system and the RCIC system. The staff's detailed review of this program is described in Section 3.1.1 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon and stainless steel components exposed to the reactor water environment.

Flow-Accelerated Corrosion Program

The FAC program is a condition monitoring program designed to monitor pipe wear in those systems that have been determined to be susceptible to FAC-related loss of material. This program includes prediction of susceptibility through modeling and testing to detect wall thinning, and is credited for managing the aging effects of carbon steel components in the HPCI system and the RCIC system. The staff's detailed review of this program is described in Section 3.1.19 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel components exposed to the reactor water environment.

Treated Water Systems Piping Inspection

The treated water systems piping inspection is a new activity at Plant Hatch that will provide for condition monitoring via one-time examinations intended to provide objective evidence that chemistry control is managing aging in piping that is not examined under another inspection program. This program is credited for managing the aging effects of components in the HPCI system, RCIC system, RHR system, CS system, primary containment purge and inerting system, and SLCS. The staff's detailed review of this program is described in Section 3.1.24 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel, stainless steel, and cast austenitic stainless steel components exposed to the reactor water, demineralized water, and suppression pool water environments. In addition, the staff finds this aging management program acceptable in managing the aging effects associated with stainless steel components exposed to a borated water environment.

Galvanic Susceptibility Inspections

Galvanic susceptibility inspection is a new activity at Plant Hatch that will provide for condition monitoring via one-time inspections to objectively determine that galvanic susceptibility is being managed for specific components within the scope of license renewal. This program is credited for managing the aging effects of components in the HPCI system, RCIC system, RHR system, CS system, and primary containment purge and inerting system. The staff's detailed review of this program is described in Section 3.1.23 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel components exposed to the reactor water, demineralized water, suppression pool water, and river water environments.

Demineralized Water and Condensate Storage Tank Chemistry Control

The demineralized water and condensate storage tank chemistry control activities mitigate aging by monitoring fluid purity and composition in the makeup water to multiple systems. These activities are regular sampling, results analysis, and when applicable, chemistry modification. This program is credited for managing the aging effects of components in the HPCI system, RCIC system, and SLCS. The staff's detailed review of this program is described in Section 3.1.6 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon and stainless steel components exposed to the demineralized water and borated water environments.

Suppression Pool Chemistry Control

The suppression pool chemistry control activities mitigate aging in components exposed to the suppression pool water by controlling fluid purity and composition in the pool. This program is credited for managing the aging effects of components in the RHR system, CS system, HPCI system, RCIC system, and primary containment purge and inerting system. The staff's detailed review of this program is described in Section 3.1.7 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon and stainless steel components exposed to the suppression pool environment. In addition, the staff finds these activities acceptable in managing the aging effects associated with the RHR heat exchangers.

Protective Coatings Program

The protective coatings program is a mitigation and condition monitoring program that provides a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the associated environment. This program is credited for managing the aging effects of components in the RHR system, CS system, HPCI system, RCIC system, primary containment purge and inerting system, SLCS, and SGTS. The staff's detailed review of this program is described in Section 3.1.20 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with the external surfaces of carbon steel components exposed to the inside, outside, and buried environments. In addition, the staff finds these activities acceptable in managing the aging effects associated with bolting materials.

Torus Submerged Components Inspection Program

The torus submerged components inspection program is a condition monitoring activity that evaluates the effectiveness of the current suppression pool chemistry control in preventing loss of material and cracking. This program is credited for managing the aging effects of components in the RHR system, CS system, HPCI system, RCIC system, and primary containment purge and inerting system. The staff's detailed review of this program is described in Section 3.1.29 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel and stainless steel components exposed to the suppression pool environment.

Plant Service Water and RHR Service Water Chemistry Control

The PSW and RHRSW chemistry control activities mitigate aging in system piping and components by controlling fluid composition. Chlorination and bromination are coordinated with periodic operation of the RHRSW to maximize chemical treatment. This program is credited for managing the aging effects of components in the PSW and RHRSW systems. The staff's detailed review of this program is described in Section 3.1.4 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel, clad carbon steel, stainless steel, cast austenitic stainless steel, gray cast iron, and copper alloy components exposed to the river water environment. In addition, the staff finds these activities acceptable in managing the aging effects associated with the RHR heat exchangers.

Plant Service Water and RHR Service Water Inspection Program

The PSW and RHRSW inspection program is a condition monitoring program that is designed to detect wall thickness degradation or fouling in the PSW and RHRSW systems. This program is credited for managing the aging effects of components in the PSW and RHRSW systems. The staff's detailed review of this program is described in Section 3.1.13 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel, stainless steel, cast austenitic stainless steel, gray cast iron, and copper alloy components exposed to the river water environment.

Gas Systems Component Inspection

The gas system component inspection is a new activity that will provide for condition monitoring via a one-time condition monitoring aging management activity designed to provide objective evidence that the aging effects predicted for systems with gases as internal environments are adequately managed. This program is credited for managing the aging effects of components in HPCI system, primary containment purge and inerting system, RHR system, RCIC system, SGTS, and post-LOCA hydrogen recombiner system (Unit 2 only). The staff's detailed review of this program is described in Section 3.1.25 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel, stainless steel, copper alloy, gray cast iron, and copper components exposed to a humid or wetted gas environment.

Passive Component Inspection Activities

The passive component inspection activities program comprises a new condition monitoring AMP that is designed to collect, report, and trend age-related data to determine the effectiveness of preventive or mitigative programs/activities credited for aging management. This activity is credited for managing the aging effects of components in the RHR system, HPCI system, RCIC system, SGTS, primary containment purge and inerting system, and post-LOCA recombiner system (Unit 2 only). The staff's detailed review of this program is described in Section 3.1.27 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel, stainless steel, cast austenitic stainless steel, and gray cast iron components exposed to a humid or wetted gas environment.

Torque Activities

The torque activities mitigate loss of preload through the use of proper torque techniques at Plant Hatch. Plant procedures specify techniques for maximizing the effectiveness of torque activities. This activity is credited for managing the aging effects of bolts in the ESF systems. The staff's detailed review of this program is described in Section 3.1.11 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon and stainless steel bolting materials.

RHR Heat Exchanger Augmented Inspection and Testing Program

The RHR heat exchanger augmented inspection and testing program will provide for condition monitoring of both the shell and tube sides of the Units 1 and 2 RHR heat exchangers. This program is credited for managing the aging effects of components in the RHR system. The staff's detailed review of this program is described in Section 3.1.28 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with the RHR heat exchangers.

Inservice Inspection (ISI) Program

The ISI program is a condition monitoring program that provides for the implementation of ASME Section XI, in accordance with the provisions of 10 CFR 50.55a. This program also includes augmented examinations required to satisfy commitments made by the applicant, and is credited for managing the aging effects of components in the RHR system. The staff's detailed review of this program is described in Section 3.1.9 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with the RHR heat exchangers.

3.3.4 Conclusions

The staff has reviewed the information in Section 3.2.3, "Engineered Safety Features," of the LRA. On the basis of this review, the staff concludes that the applicant has adequately identified the aging effects, and has demonstrated that the aging effects associated with the ESF 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.

3.4 Auxiliary Systems

3.4.1 Introduction

The applicant provided the results of its AMR for the auxiliary systems for license renewal in Section 3.2.4, "Auxiliary Systems," and Section C.2 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the auxiliary systems will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Section 3.2.4 of the LRA contains six-column tables for each auxiliary system, which represents an overview of the aging management review results. The tables list the in-scope components of each system, along with each component's in-scope function, materials of construction, working environment, aging effects, and the associated aging management programs that are credited with managing the aging effects. The tables also reference the commodity group associated with each component. The commodity groups are described in Section C.2 of the LRA. Each commodity group is associated with a common environment and group of materials. The commodity groups, in turn, reference Section C.1 of the LRA, which provides a detailed discussion of the environments, materials and associated aging effects. The commodity groups also reference Section A of the LRA, which describes the aging management programs that manage the specified aging effects. The applicant submitted a supplemental description of its aging management programs in Section B of the LRA on October 10, 2000. The staff reviewed these sections of the application to determine whether the applicant presented adequate information to meet the requirements set forth in 10 CFR 54.21(a)(3).

External environments are defined in Sections 3.1.2.8, "Inside;" 3.1.2.9, "Outside;" and 3.1.2.10, "Buried or Embedded" of the LRA. "Inside" external environments are defined as environments where equipment is sheltered from the weather. "Outside" external environments are defined as environments found outside a structure where equipment would not be sheltered from the weather. "Buried or embedded" external environments are defined as environments beneath the surface of the ground (in some cases with controlled backfill) or embedded in structural concrete. Structures and components which perform their functions in external environments are, in general, discussed in Sections 3.2, 3.3, 3.4, 3.5, 3.6, and 3.7 of the LRA, and are evaluated in Sections 3.6 and 3.7 of this SER, unless otherwise noted.

3.4.2 Summary of Technical Information in the Application

The applicant provided an aging management review of 20 auxiliary systems that are considered to be within the scope of license renewal. A brief description of each system is presented below.

Access Doors

The secondary containment access doors provide access for personnel and equipment. In addition, the secondary containment, in conjunction with the primary containment and other engineering safeguards, provides the capability to limit the release of radioactive materials to the environment.

Condensate Transfer and Storage System

The condensate transfer and storage system provides the plant system makeup, receives reject flow, and provides condensate for any continuous service needs and intermittent batch-type services. A 500,000 gallon CST supplies the various unit requirements. The CST provides the preferred supply to the HPCI and RCIC systems.

Control Building Heating Ventilation and Air Conditioning (HVAC) System

Under normal and post-accident plant conditions, the control building HVAC system controls temperature and air movement, filters fresh-air supply for personnel comfort, removes heat from the plant equipment to optimize performance, minimizes the potential for exhaust air to enter the supply air, and detects and limits the introduction of radioactive material into the main control room. The control room HVAC system provides cooling and maintains a controlled environment for personnel safety and habitability in the control room during normal and accident conditions. The system also provides a controlled temperature to ensure the reliability of the main control room components.

Control Rod Drive System

The CRD hydraulic system provides pressurized, demineralized water for the cooling and manipulation of the CRD mechanisms. The CRD system also provides purge water for the reactor water cleanup pump and reactor recirculation pump seals. The alternate rod insertion system is a subsystem of the CRD system. It is a backup means of scramming the reactor by venting the scram air header. The alternate rod insertion system is independent of the reactor protection system, and was installed to reduce the probability of an anticipated transient without scram event.

Cranes, Hoists, and Elevators System

The reactor building crane is the only in-scope component for the cranes, hoists, and elevators system. The reactor building crane moves major components for refueling operations and maintenance. The Unit 1 reactor building crane provides service to both Unit 1 and Unit 2.

Drywell Pneumatics System

The drywell pneumatics system supplies the motive gas to various valves inside the drywell.

Emergency Diesel Generators System

The emergency diesel generators provide emergency backup power to 4160-V ac emergency buses E, F, and G in the event of a loss of offsite power.

Fire Protection System

The fire protection system ensures, through a defense-in-depth design, that a fire will not prevent the necessary safe plant shutdown functions from occurring. The program also decreases the risk of radioactive releases to the environment during a fire. The program consists of detection and extinguishing systems, administrative controls and procedures, and trained personnel. The applicant gave the primary design consideration to locating redundant safe shutdown circuits and components in distinct areas separated by fire barriers to prevent the propagation of fire to adjacent areas. Fire barriers consist of fire-rated doors, dampers, and penetration seals. The barriers are designed to contain a design-basis fire. The fire protection program at Plant Hatch also includes an early warning fire detection system. Two 300,000-gallon dedicated storage tanks provide the water supply for the fire protection system inside the protected area. These tanks, in turn, are supplied by two deep wells with strained and filtered water supplies for normal makeup. The fire protection system also includes cardox fire suppression for the emergency diesel generators to provide an automatic gaseous total flooding fire suppression system for a diesel engine compartment fire to contain and control the level of fire damage, and an automatic gaseous fire suppression system for the computer room and the cable spreading room. This is a total flooding system actuated by ionization detection.

With regard to the inspection frequency of the fire system components, the applicant lists in Section B.2.1 of the LRA, the different inspection intervals for the water-based fire protection systems, fire protection pump diesel fuel oil supply system, compressed gas-based fire suppression systems, fire penetration seals, cable tray enclosures, and fire doors. In addition to the systems listed above, the applicant describes a one-time inspection called the "Sprinkler Head Inspections," that will be performed at or before the start of the extended period of operation for closed sprinkler heads within the scope of license renewal.

Fuel Oil System

The fuel oil system receives, stores, and supplies fuel oil to other systems including the emergency diesel generator system.

Instrument Air System

The instrument air system provides dried and filtered air to all of the air-operated instruments and valves throughout the entire plant (with the exception of the equipment inside the drywell). This system is made up of two subsystems, one of which is non-interruptible, while the other is interruptible. The non-interruptible system provides instrument air for the operation of certain emergency system components. The interruptible system provides instrument air to all other components. The drywell pneumatic system (discussed in more detail below) supplies the motive gas for components within the drywell.

Insulation System

Insulation helps to retain heat in the process piping and equipment, to prevent moisture from condensing on cold surfaces, to protect equipment and personnel from high temperatures, to prevent piping from freezing if cold areas of the plant, and to protect heat tracing from damage. The applicant also credits insulation in heat load calculations for safety-related rooms. Failure of this insulation could allow the heat load of the room to exceed the capability of the HVAC system, thus exceeding the design temperature of the room.

Outside Structures HVAC System

This group includes the intake structure HVAC and the diesel generator building HVAC systems. The intake structure HVAC system protects the intake structure equipment from adverse temperature conditions that could affect the reliability of the equipment. The diesel generator building HVAC system protects diesel generator building equipment from adverse temperature conditions that could affect the reliability of the equipment. In addition, the emergency diesel generator battery room ventilation system exhausts hydrogen from the battery rooms, and the emergency diesel generator building oil storage room ventilation exhausts fumes from the oil storage room in the event of fire.

Plant Service Water System

The plant service water system removes the heat that is generated from various systems. This system provides circulating water system makeup from screened Altamaha River water and, after cooling heat exchangers, provides makeup water to the circulating water flume. This system is also available for fire-fighting, radwaste dilution, and emergency spent fuel pool makeup.

Primary Containment Chilled Water System (Unit 2 Only)

The primary containment chilled water system maintains the drywell area below a maximum volumetric average temperature of 150°F dry bulb during normal operation. This function is fulfilled by providing chilled water to the drywell fan coil units. Reactor building service water provides the chiller condenser cooling water, while demineralized water provides makeup for the system.

Reactor Building Closed Cooling Water System

The reactor building closed cooling water system provides cooling water to auxiliary equipment located in the reactor building.

Reactor Building HVAC System

The reactor building HVAC system performs many functions. It provides an environment with controlled temperature and airflow to ensure the comfort and safety of operating personnel and to optimize equipment performance by removing heat from the plant equipment. It promotes air movement from operating areas and areas of lower airborne radioactivity potential to areas of greater airborne radioactivity potential prior to final filtration and exhaust. It minimizes the release of potential airborne radioactivity to the environment during normal plant operation by exhausting air, through a filtration system, from the areas in which a significant potential for radioactive particulates and/or radioiodine contamination exists. It provides a source of cooling to support the operation of the emergency core cooling systems. Lastly, the system provides isolation capability to maintain secondary containment integrity and support operation of the standby gas treatment system. The reactor building HVAC system uses a combination of air conditioning, heating, and once-through ventilation. Heat removal is provided by ventilation air and chilled-water (Unit 2 only) and service-water cooling coils served by the reactor and radwaste building chilled water system and the plant service water system, respectively. Hot water heating coils, served by the plant heating system, are supplied for heating.

Refueling Equipment System

The refueling platform equipment assembly handles and transports reactor core internals and service and handling equipment associated with the refueling operation. The refueling platform is a bridge structure that spans the refueling pool and the reactor well and travels on rails which extend the length of the fuel storage pool and the reactor well. The fuel grapple extends downward, below the underside of the refueling platform, into the pool or reactor well.

Sampling System

The primary containment hydrogen and oxygen sampling system monitors hydrogen and oxygen in the primary containment (drywell and torus).

Tornado Vents System

The tornado vents act as blowout panels for venting the reactor and turbine building roofs (1) against a wind velocity of 300 mph, (2) when the internal static pressure in the building is increased to 55 lb/ft^2, or (3) when the temperature reaches approximately 212 °F. A rapid depressurization of air surrounding site structures can occur if a tornado funnel suddenly engulfs a structure. Venting is accomplished by placing blowout panels, designed to fail at a pressure lower than the safe building capability for internal pressure, to relieve excess pressure in all essential parts of such structures.

Traveling Water Screens/Trash Racks System

The intake structure is equipped with trash screens and rakes to keep debris out of the pump wells. The traveling water screens prevent debris from entering the portion of the intake structure from which the pumps take suction. Larger debris is prevented from reaching the screens by the trash racks. The debris is removed from the screens by the screen wash water.

3.4.2.1 Aging Effects and Aging Management Programs

The applicant discussed the aging effects and aging management programs for the various auxiliary system components and environments at Plant Hatch in Sections C.1 and C.2 of the LRA. The applicant approached its aging management review in a manner that the staff and industry commonly refer to as the commodity group approach. Commodities are groups of structures or components that have similar intended functions and materials of construction and operate in similar environments. Because they are similar in material and environment, they can experience common aging effects, and common aging management programs can be credited for managing those aging effects. This approach is intended to achieve efficiency in the aging management review process. There are more than 20 commodity groups related to auxiliary systems because of the wide variety of environments that exist in the auxiliary systems. Therefore, the staff chose to present the applicant's aging management review based on environment, rather than commodity group, in order to consolidate and streamline this SER. These environments include demineralized water, dried and wetted gases, inside (sheltered) and outside (nonsheltered), raw water (including submerged components), closed cooling water, concrete embedment, and fuel oil environments. Each of these environments, the materials exposed to these environments, and the associated aging effects and aging management programs identified by the applicant are summarized below.

Demineralized Water

Demineralized water at Plant Hatch contains no corrosion inhibiting chemical or biocide additions, and provides no control of dissolved oxygen concentrations. Acceptable levels for impurities vary among systems driven by the relative potential for any given system to supply water to the reactor pressure vessel. Three auxiliary systems (control rod drive system, condensate transfer and storage system, and emergency diesel generators system) contain stainless steel, cast austenitic stainless steel, carbon steel, galvanized steel, or aluminum alloy components exposed to a demineralized water environment. The applicant discussed the aging management review for the auxiliary system structures and components exposed to a demineralized water environment in Section C.2.2.2 of the LRA. The applicant identified several forms of corrosion that may result in loss of material (e.g., general corrosion, galvanic corrosion, crevice corrosion, MIC, pitting, and erosion corrosion). To manage this aging effect, the applicant relies on the following aging management programs:

- demineralized water and condensate storage tank chemistry control
- treated water systems piping inspections
- galvanic susceptibility inspections
- condensate storage tank inspection

Dried and Wetted Gases

The applicant defined the gas environment as any line that contains noncondensable gases and includes both dried and nondried (wetted) gases. Dried gases describe any process gas including, but not limited to, air, nitrogen (including cryogenic), carbon dioxide, hydrogen, helium, and fluorocarbons supplied from a tank or bottle or filtered and desiccated to remove moisture prior to entering the system. Five auxiliary systems (control rod drive system, instrument air system, drywell pneumatics system, fire protection system, and the control building HVAC system) contain carbon steel, stainless steel, or copper/copper alloy components exposed to a dried gas environment. The applicant discussed the aging management review for the auxiliary system structures and components exposed to a dried gas environment in Section C.2.2.8 and section C.2.3.3 of the LRA. Because sufficient moisture to drive the various corrosion mechanisms is not present, there are no aging effects that require management and, therefore, no aging management programs were identified.

Wetted gases include hydrogen, oxygen, air or nitrogen containing humidity or significant moisture. Wetted gas environments are found inside of buildings, inside the drywell, and outside of buildings. These gases are assumed to contain sufficient entrained moisture and oxygen to enable pooling of liquid at low or especially cool locations and promote corrosion. Eight auxiliary systems (control rod drive system, sampling system, emergency diesel generator system, reactor building HVAC system, outside structures HVAC system, fire protection system, fuel oil system, and control building HVAC system) contain carbon steel, stainless steel, galvanized steel, copper/copper alloy, aluminum, or cast iron components, as well as gasket materials exposed to a wetted gas (this includes air) environment. The applicant discussed the aging management review for the auxiliary system structures and components exposed to a wetted gas environment in Section C.2.2.9 Section C.2.3.3 and Section C.2.6.7 of the LRA. The applicant identified several forms of corrosion that may result in loss of material (e.g., general corrosion, selective leaching, galvanic corrosion, crevice corrosion, MIC, and pitting). The applicant also identified cracking of gasket materials due to compaction and settling, exposure to moisture, and thermal effects. To manage these aging effects, the applicant relies on the following aging management programs:

- gas systems component inspections
- passive component inspection activities
- fire protection activities

Inside and Outside Environments

An inside environment indicates that the equipment is sheltered from the weather. The inside environment assumes 50-percent to 90-percent humidity, an ambient temperature less than 120°F (except for primary containment), and a maximum radiation level of 9.0×10^6 rads. The primary containment environment assumes 40-percent to 90-percent humidity, a maximum temperature of 150°F defined by data obtained from RTDs, and a maximum radiation level of 9.17×10^7 rads outside the sacrificial shield wall. The applicant defines "outside" as any external environment found outside any structure that would protect it from the weather. The applicant assumes 0 percent to 100 percent humidity, an ambient temperature less than 120°F, and no radiation.

Eighteen auxiliary systems (control rod drive system; refueling equipment system; insulation system; access doors; condensate transfer and storage system; plant service water system; reactor building closed cooling water system; instrument air system; primary containment chilled water system; drywell pneumatics system; cranes, hoists and elevators system; tornado vents system; reactor building HVAC system; traveling screen/trash rack system; outside structures HVAC system; fire protection system; fuel oil system; and control building HVAC system) contain carbon steel, aluminum, stainless steel, acrylic, galvanized steel, cast iron, ceramic, copper/copper alloy, or various insulating/gasket type materials or specialized fire protection materials exposed to an inside (sheltered) and/or outside (nonsheltered) environment. The applicant discussed the aging management review of these materials in these environments in Sections C.2.2.10, C.2.6.3, C.2.4.4, C.2.4.1, C.2.4.2., C.2.6.6, C.2.6.8, C.2.3.4, and C.2.6.7 of the LRA. The applicant identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, and pitting). The applicant identified loss of preload as an applicable aging effect for bolting due to embedment, gasket creep, thermal effects, or self loosening. The applicant identified cracking of acrylic due to weathering as well as cracking, and change in material properties for insulating/gasket type materials due to compaction and settling, exposure to moisture, and thermal effects. To manage these aging effects, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program
- overhead crane and refueling platform inspections

- equipment and piping insulation monitoring program
- fire protection activities
- gas systems component inspections
- passive component inspection activities

Raw Water

Plant Hatch has two sources of raw water, including river water and well water. River water is supplied from the Altamaha River via the intake structure. The structure has rough screens in place to prevent clogging of the vertical turbine pumps and discharge strainers. Some debris, silt, and macroorganisms may be introduced into the plant service water and residual heat removal service water systems. Well water is supplied from deep draft wells located on site. The water is mechanically filtered using the demineralizing system filters to remove macroorganisms and silt. Well water is used for the fire protection system only. Three auxiliary systems (plant service water system, traveling water screens/trash rack system, and the fire protection system) contain stainless steel, carbon steel, cast austenitic stainless steel, cast iron, copper alloys, galvanized steel, or aluminum components exposed to a raw water environment. The applicant discussed the aging management review of these materials in this environment in Sections C.2.2.6, C.2.6.3, and C.2.3.1 of the LRA. The applicant identified several forms of corrosion that may result in loss of material (e.g., general corrosion, galvanic corrosion, crevice corrosion, MIC, and pitting) and flow blockage due to fouling. To manage these aging effects, the applicant relies on the following aging management programs:

- plant service water and residual heat removal service water inspection program
- plant service water and residual heat removal service water chemistry control
- structural monitoring program
- galvanic susceptibility inspections
- protective coatings program
- fire protection activities

Closed Cooling Water

Plant Hatch monitors the closed cooling water for detrimental impurities, although the parameters are less restrictive than those for reactor water or auxiliary system water environments. The applicant adds corrosion inhibitors to reduce the corrosion rate to an acceptable level. A basic pH is maintained to increase the effectiveness of the corrosion inhibitors and promote the development of protective corrosion films. Plant Hatch maintains biocide levels to prevent significant microorganism growth. Two auxiliary systems (the reactor building closed cooling water system and the primary containment chilled water system) have carbon steel, stainless steel, and copper alloy components exposed to a closed cooling water environment. The applicant discussed the aging management review of the materials in this environment in Section C.2.2.5 of the LRA. The applicant identified several forms of corrosion that may result in loss of material (e.g., general corrosion, galvanic corrosion, crevice corrosion, MIC, and pitting). To manage this aging effect, the applicant relies on the following aging management programs:

- closed cooling water chemistry control
- treated water systems piping inspections

Embedded in Concrete

The fire protection system contains penetration seals embedded in concrete. The applicant discussed the aging management review in Section C.2.3.4 of the LRA. Aging effects that require management include loss of material due to corrosion (e.g., general corrosion, crevice corrosion, and pitting) or wear and fretting, cracking within concrete/fire barrier materials due to thermal effects and/or compaction and settling, and change in material properties of fire barrier materials due to thermal degradation. To manage these aging effects, the applicant relies on the fire protection activities program.

Fuel Oil

Fuel oil is any oil utilized to fuel an internal combustion engine. Two auxiliary systems (fire protection system and the fuel oil system) contain carbon steel, stainless steel, copper/copper alloy and cast iron components exposed to a fuel oil environment. The applicant discussed the aging management review of these materials in this environment in Section C.2.3.2 and Section C.2.2.7 of the LRA. The applicant identified several forms of corrosion that may result in loss of material (e.g., general corrosion, galvanic corrosion, crevice corrosion, MIC, and pitting). To manage this aging effect, the applicant relies on the following aging management programs:

- diesel fuel oil testing
- fire protection activities

External Environments

The auxiliary system environments discussed above are based on the dominant operating environment of the components which, generally speaking, is the internal environment (e.g., raw water running through piping). The applicant discussed the aging effects due to external environments in Section C.2.4 of the LRA. These external environments include inside, outside, buried or embedded, and a special section for insulation commodities. The staff's evaluation of the applicant's treatment of aging effects caused by external environments can be found in Section 3.6 of this SER, and are generally not discussed for the auxiliary system structures and components in this section. However, when the external environment is the dominant operating environment for the structure or component, the aging effects and associated aging management programs are included in this section of the SER.

Thermal Fatigue

The applicant identified cracking due to thermal fatigue as an aging effect for the auxiliary system components. The applicant stated that all non-Class 1 components are enveloped by a time-limited aging analysis that adequately addresses this aging effect without regard to individual component or system conditions. The applicant discusses this analysis in Section 4.2.3 of the LRA. The staff's evaluation of this analysis is in Section 4.2 of this SER.

Operating Experience

The applicant stated it collected industry operating experience from sources such as NRC generic letters, bulletins and information notices; General Electric service information letters; Institute for Nuclear Power Operations (INPO) significant operating event reports; and topical information from various industry working groups. The applicant obtained plant-specific information through plant walkdowns, interviews, and records searches of their condition reporting database that covers the last 5 years of operation. The applicant presented brief discussions of this operating experience, both plant-specific and industry-wide, in each commodity group.

The applicant concluded that it identified the appropriate aging effects and associated aging management programs that would ensure that the intended function of the components of the auxiliary systems would be maintained consistent with the current licensing basis, under all design loading conditions during the period of extended operation.

3.4.3 Staff Evaluation

The applicant described its aging management review of the auxiliary systems for license renewal in Section 3.2.4 and Sections A, B (submitted October 10, 2000), and C of the LRA. The staff reviewed these sections of the application to determine whether the applicant presented adequate information to meet the requirements stated in 10 CFR 54.21(a)(3). In this section of the safety evaluation report, the staff provides its evaluation of the aging management review for the auxiliary systems.

3.4.3.1 Aging Effects

Access Doors

Access doors consist of structural carbon steel exposed to inside and outside environments. The applicant identified loss of material as an applicable aging effect. The staff agrees with the applicant's identification of aging effects.

Condensate Transfer and Storage System

The condensate transfer and storage system contains components exposed to a demineralized water environment. The applicant identified loss of material as an applicable aging effect associated with component materials in a demineralized water environment. The condensate transfer and storage system also contains stainless steel bolting exposed to an outside environment. The applicant identified loss of preload as an applicable aging effect. The staff agrees with the applicant's identification of aging effects.

Control Building HVAC System

The control building HVAC system contains both metallic and nonmetallic components exposed to a air (potentially wetted), dried gas, inside, and raw water environments. In the air environment, the applicant identified the following applicable aging effects:

- loss of material for metallic components;
- matierial property changes for non-metallic.

In the dried gas environment, the applicant identified no aging effects associated with component materials.

In the inside environment, the applicant identified the following applicable aging effects:

- loss of material for carbon steel bolting and the condensing unit shell;
- loss of preload for carbon steel bolting.

Lastly, the condensing unit shell in the control building HVAC is also exposed to a raw water environment. The applicant identified loss of material as the applicable aging effect for this environment.

In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000. A full discussion of this issue may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, the staff concludes that the applicant has adequately identified the aging effects associated with the control building HVAC system.

Control Rod Drive System

The CRD system contains components exposed to a demineralized water environment. The applicant identified loss of material as an applicable aging effect associated with component materials in a demineralized water environment. The CRD system also contains components exposed to a dried gas environment. The applicant identified no aging effects associated with CRD component materials in a dried gas environment. The CRD system also contains components exposed to a wetted gas environment. The applicant identified loss of material as an applicable aging effect. The CRD system contains carbon and low alloy carbon steel bolts exposed to an inside environment. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000. A full discussion of this issue may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, the staff concludes that the applicant has adequately identified the aging effects associated with the CRD system.

Cranes, Hoists and Elevators System

The reactor building crane is the only in-scope component for the cranes, hoists, and elevators system. The reactor building crane contains carbon steel components exposed to an inside environment. The applicant identified loss of material as an applicable aging effect. The staff agrees with the applicant's identification of aging effects.

Drywell Pneumatics System

The drywell pneumatics system contains components exposed to a dried gas environment. The applicant identified no aging effects associated with component materials in a dried gas environment. This system also contains carbon steel and stainless steel bolts exposed to an inside environment. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000. A full discussion of this issue may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, the staff concludes that the applicant has adequately identified the aging effects associated with the drywell pneumatics system.

Emergency Diesel Generators System

The emergency diesel generator (EDG) system contains metallic components (alloy, carbon, and stainless steels, copper and copper alloy, and cast iron) exposed to moist air, lube oil, raw water, and demineralized water and ethylene glycol (antifreeze) environments. The applicant identified loss of material and cracking due to fatigue as aging effects. In addition, the applicant identified loss of preload in the moist air environment, and loss of heat exchanger performance in the raw water environment. In Table 3.2.4-12 of the LRA, the applicant did not identify loss of preload as an aging effect for bolting in the EDG system. In RAI 3.4-10(c), dated July 28, 2000, the staff requested that the applicant provide the basis for excluding loss of preload as an aging effect for bolting in the EDG system. The applicant responded to this RAI in its letter dated October 10, 2000, stating that bolting was not a separate mechanical component/commodity requiring aging management for the EDG system. However, as part of the resolution to Open Item 2.3.3.2-1(b), the applicant clarified that bolting will be managed by the torque activities AMP.

On the basis of the information provided by the applicant in the LRA, the staff concludes that the applicant has adequately identified the aging effects associated with the EDG system.

Fire Protection System

The fire protection system contains many components fabricated from various materials and exposed to an inside environment. The applicant identified loss of material and cracking as applicable aging effects for the carbon steel, nonferrous metal, ceramic and organic components. The applicant also identified a change in material properties for insulating materials and penetration seals. The applicant did not identify any aging effects for fire doors constructed from materials other than carbon steel for which loss of material is an applicable aging effect. The fire protection system also has components exposed to raw water. The applicant identified loss of material, cracking, and flow blockage as applicable aging effects associated with component materials in a raw water environment. The fire protection system also has components exposed to fuel oil. The applicant identified loss of material and cracking as applicable aging effects associated with component materials in a fuel oil environment. Finally, the fire protection system has components exposed to either a dried gas or an air (potentially wetted) environment. The applicant identified no aging effects for components exposed to a dried gas environment. For those components exposed to an air environment, the applicant identified loss of material and cracking as applicable aging effects.

The fire protection system also contains carbon steel bolting exposed to inside and outside environments. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000. A full discussion of this issue may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, the staff concludes that the applicant has adequately identified the aging effects associated with the fire protection system.

Fuel Oil System

The fuel oil system contains components exposed to a fuel oil environment. The applicant identified loss of material and cracking as applicable aging effects associated with component materials in a fuel oil environment. Lastly, the fuel oil system contains components exposed to an air (potentially wetted) environment. The applicant identified loss of material and cracking as applicable aging effects associated with component materials in an air (potentially wetted) environment.

The fuel oil system also contains carbon steel bolts exposed to an inside environment. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000. A full discussion of this issue may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, the staff concludes that the applicant has adequately identified the aging effects associated with the fuel oil system.

Instrument Air System

The instrument air system contains components exposed to a dried gas environment. The applicant identified no aging effects associated with component materials in a dried gas environment. The instrument air system also contains carbon and stainless steel bolts exposed to an inside environment. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000. A full discussion of this issue may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, the staff concludes that the applicant has adequately identified the aging effects associated with the instrument air system.

Insulation System

The insulation system contains metallic and insulating components exposed to inside and outside environments. The applicant identified loss of material and cracking as applicable aging effects for the metallic components in these environments. The applicant also identified, for the insulation, loss of material due to intrusion of water or wear, cracking due to thermal degradation or intrusion of water, and a change in material properties due to compaction or settling. The staff agrees with the applicant's identification of aging effects.

Outside Structures HVAC System

The outside structures HVAC system contains components exposed to air (potentially wetted), inside, and outside environments. The applicant identified loss of materials as an applicable aging effect associated with component materials in an air (potentially wetted) environment. The system also contains carbon steel bolts and unit heater housing exposed to inside and outside environments. In addition, the applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000. A full discussion of this issue may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, the staff concludes that the applicant has adequately identified the aging effects associated with the outside structures HVAC system.

Plant Service Water System

The plant service water system contains a carbon steel pump sub-base exposed to an inside environment. The applicant identified loss of material as an applicable aging effect.

The plant service water system contains components exposed to a raw water (river water) environment. The applicant identified loss of material and cracking as applicable aging effects associated with component materials in a raw water environment. The applicant also identified flow blockage as an applicable aging effect due to corrosion product buildup, biofouling, particulate fouling, or precipitation fouling. The plant service water system also contains carbon and low-alloy steel bolts exposed to inside and outside environments. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000. A full discussion of this issue may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, the staff concludes that the applicant has adequately identified the aging effects associated with the plant service water system.

Primary Containment Chilled Water System (Unit 2 Only)

The primary containment chilled water (PCCW) system contains components exposed to the closed cooling water environment. The applicant identified loss of material as an applicable aging effect associated with component materials in a closed cooling water environment. The PCCW system also contains carbon steel bolts exposed to an inside environment. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000. A full discussion of this issue may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, the staff concludes that the applicant has adequately identified the aging effects associated with the primary containment chilled water system (Unit 2 only).

Reactor Building Closed Cooling Water System

The reactor building closed cooling water system contains components exposed to a closed cooling water environment. The applicant identified loss of material and cracking as applicable aging effects associated with the component materials in a closed cooling water environment. This system also contains carbon and low-alloy carbon steel bolts exposed to inside environments. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000. A full discussion of this issue may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, the staff concludes that the applicant has adequately identified the aging effects associated with the reactor building closed cooling water system.

Reactor Building HVAC System

The reactor building HVAC system contains components exposed to an air (potentially wetted) environment. The applicant identified loss of material as an applicable aging effect associated with component materials in an air (potentially wetted) environment. This system also contains carbon steel bolts exposed to inside and outside environments. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000. A full discussion of this issue may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, the staff concludes that the applicant has adequately identified the aging effects associated with the reactor building HVAC system.

Refueling Equipment System

The refueling equipment system contains components exposed to an inside environment. The applicant identified loss of material as an applicable aging effect associated with the component materials in an inside environment. The staff agrees with the applicant's identification of aging effects.

Sampling System

The sampling system contains components exposed to a wetted gas environment. The applicant identified loss of material and cracking as applicable aging effects associated with component materials in a wetted gas environment. The staff agrees with the applicant's identification of aging effects.

Tornado Vents System

The tornado relief vent assemblies contain metallic and acrylic components exposed to an inside and outside environment. The applicant identified no aging effects for the metallic components.

The applicant identified cracking as an applicable aging effect for the acrylic components. The staff agrees with the applicant's identification of aging effects.

Traveling Water Screens/Trash Racks System

The traveling water screens/trash rack system contains components exposed to or submerged in raw water. The applicant identified loss of material, cracking, and fouling as applicable aging effects associated with component materials in a raw water environment. This system also contains carbon steel bolts exposed to an outside environment. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000. A full discussion of this issue may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, the staff concludes that the applicant has adequately identified the aging effects associated with the traveling water screens/trash racks system.

Vibration Loading

The applicant did not identify cracking due to vibration loading as an aging effect for the auxiliary system components. The staff is aware that some piping system degradation (e.g., loss of integrity of bolted closures, cracking of welds, and loosening of bolts) may be caused by vibration (mechanical or hydrodynamic) loading. In many tables in Section 3.2.4 of the LRA, the applicant identified loss of preload as an aging effect for bolting. In Section C.1 of the LRA, the applicant indicated that loss of preload included self-loosening of bolting that may be caused by vibration. Thus, the staff was not clear whether the applicant had considered cracking of auxiliary system components (in particular piping welds and HVAC ducting) that may be subjected to a high-vibration environment. In RAI 3.4-10(b), dated July 28, 2000, the staff requested that the applicant clarify whether it had considered these vibration related aging effects in the AMR for the auxiliary systems discussed in Section 3.2.4 of the LRA. The applicant responded to the staff's RAI in its letter dated October 10, 2000, stating that vibration- induced cracking in piping welds and HVAC ducting is indicative of an insufficient design or failure to follow good bolting practices following maintenance, neither of which is age-related. Therefore, the applicant concluded that vibration-induced cracking is not an applicable aging effect. It should be noted that the control building HVAC system includes elastomeric isolators. Elastomers may crack, harden, or lose strength due to relative motion between vibrating equipment, exposure to warm moist air, temperature changes, oxygen, and/or radiation. If these isolators degrade, vibration and subsequent dynamic loads applied to the ductwork and fasteners cannot be eliminated. The applicant considered the degradation of elastomeric isolators, including gaskets and flexible connectors, in the control building HVAC system. The isolators are shown in Table 3.2.4-20 of the LRA as "ductwork flex connectors," and the aging management review is presented in Section C.2.6.7 of the LRA. By including the isolators in the aging management review for this system, the staff finds that the applicant has adequately addressed the potential for vibration-related aging effects for the control building HVAC system. In RAI 3.4-12, the staff also requested that the applicant discuss how this potential aging effect is managed for the reactor building HVAC system. In its submittal dated October 10, 2000, the applicant clarified that the reactor building HVAC system design is such that isolators are not required. As this design has demonstrated acceptable operating experience, the staff concludes that vibration-related aging effects are not applicable to the reactor building HVAC system. The staff finds that the applicant's responses adequately address the vibration-related aging effects for auxiliary systems.

External Environments

The applicant discussed the aging effects due to external environments in Section C.2.4 of the LRA. These external environments include inside, outside, and buried or embedded environments, and a special section for insulation commodities. The staff's evaluation of the applicant's treatment of aging effects caused by external environments can be found in Section 3.6 of this SER, and are generally not discussed for the auxiliary system structures and components in this section. However, when the external environment is the dominant operating environment for the structure or component, the aging effects and associated aging management programs are included in this section of the SER.

Thermal Fatigue

The applicant identified cracking due to thermal fatigue as an aging effect for the auxiliary system components. The applicant stated that all non-Class 1 components (with the exception of the jacket water cooling subsystem of the emergency diesel generators) are enveloped by a time-limited aging analysis that adequately addresses this aging effect without regard to individual component or system conditions. The applicant discusses this analysis in Section 4.2.3 of the LRA. The staff's evaluation of this analysis is in Section 4.2 of this SER. For the jacket water cooling subsystem components, there is no TLAA under the control of the applicant to demonstrate that thermal fatigue is managed by design. Therefore, the applicant relies on diesel generator maintenance activities to manage cracking of the jacket water cooling subsystem.

Summary of the Review of Aging Effects' Operating Experience

The staff has reviewed the information presented by the applicant regarding plant-specific, as well as industry-wide, experience to support its identification of applicable aging effects. This included the description of the internal environments and materials of fabrication for these systems. On the basis of the information, the staff concludes that the applicant has identified the aging effects for the commodity groups in the auxiliary systems that are consistent with published literature and industry experience.

3.4.3.2 Aging Management Programs

Access Doors

To manage aging effects for structural carbon steel components exposed to either an inside or outside environment, the applicant relies on the following aging management programs:

- structural monitoring program
- protective coatings program

The structural monitoring program provides for visual inspection of structural components on a regular, periodic basis. In addition, the carbon steel access doors are coated with an inorganic zinc primer and epoxy topcoat or are galvanized steel. The protective coatings program provides for periodic inspection of component surfaces to ensure that this coating is intact and providing adequate protection. This program also provides for proper corrective actions to prevent significant degradation (e.g., replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.22 and 3.1.20 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Condensate Transfer and Storage System

To manage aging effects for components exposed to a demineralized water environment, the applicant relies on the following aging management programs:

- demineralized water and condensate storage tank chemistry control
- treated water systems piping inspections

The demineralized water and condensate storage tank chemistry control program serves to manage loss of material due to corrosion by limiting concentrations of impurities, total organic carbon, and conductivity. The treated water systems piping inspections is a one-time inspection program to validate the adequacy of the demineralized water and condensate storage tank chemistry control program in mitigating the loss of material within carbon steel and stainless piping. The staff's detailed review of these programs may be found in Sections 3.1.6 and 3.1.24 of this SER.

To manage loss of preload for stainless bolting exposed to an outside environment, the applicant relies on the torque activities program, which provides detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. The staff's detailed review of this program may be found in Section 3.1.11 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Control Building HVAC System

To manage aging effects for components exposed to an air environment, the applicant relies on the following aging management programs:

- gas systems component inspections
- passive component inspection activities

The applicant designed both of these programs to address corrosion-related aging degradation in gas-bearing systems. The gas systems component inspections program is a new, one-time inspection program that inspects a sample of components that are considered unlikely (e.g., stainless steel components) to suffer age-related degradation. In contrast, the passive component inspection activities provide for the inspection of normally inaccessible components during maintenance activities. This latter program is for those components considered more likely to suffer age-related degradation. The staff's detailed review of these programs may be found in Sections 3.1.25 and 3.1.27 of this SER.

To manage aging effects for carbon steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

To manage aging effects for the condensing unit shell and tubing exposed to raw water, the applicant relies on the following aging management programs:

- PSW and RHRSW inspection program;

- PSW and RHR service water chemistry control program.

The PSW and RHRSW inspection program is designed to detect wall thickness degradation or fouling in the PSW and RHRSW systems. This program focuses on locations that the applicant determines are prone to corrosion and prone to clogging such as small diameter piping and low point drains, respectively. The PSW and RHRSW chemistry control program is intended to mitigate aging in system piping and components by controlling fluid composition. The service water system is treated with sodium hypochlorite and sodium bromide.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Control Rod Drive System

To manage aging effects for components exposed to a demineralized water environment, the applicant relies on the following aging management programs:

- demineralized water and condensate storage tank chemistry control
- treated water systems piping inspections
- galvanic susceptibility inspections (for carbon steel components only)

The demineralized water and condensate storage tank chemistry control program serves to manage loss of material due to corrosion by limiting concentrations of impurities, total organic carbon, and conductivity. The treated water systems piping inspections comprise a one-time inspection program to validate the adequacy of the demineralized water and condensate storage tank chemistry control program in mitigating loss of material within carbon steel and stainless steel piping. The galvanic susceptibility inspections comprise another one-time inspection program to examine carbon steel to stainless steel dissimilar metal welds to identify potential loss of material due to galvanic corrosion. The staff's detailed review of these programs may be found in Sections 3.1.6, 3.1.24, and 3.1.23 of this SER.

To manage aging effects for carbon steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

To manage aging effects for components exposed to a wetted gas environment, the applicant relies on the following aging management programs:

- gas systems component inspections
- passive component inspection activities

The applicant designed both of these programs to address corrosion-related aging degradation in gas-bearing systems. The gas systems component inspections program is a new, one-time inspection program that inspects a sample of components that are considered unlikely (e.g., stainless steel components) to suffer age-related degradation. In contrast, the passive component inspection activities provide for the inspection of normally inaccessible components during maintenance activities. This latter program is for those components considered more likely to suffer age-related degradation. The staff's detailed review of these programs may be found in Sections 3.1.25 and 3.1.27 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

<u>Cranes, Hoists and Elevators Systems</u>

The reactor building crane is the only in-scope component for the cranes, hoists, and elevators system. To manage aging effects for carbon steel components exposed to an inside environment, the applicant relies on the following aging management programs:

- overhead crane and refueling platform inspection
- protective coatings program

The overhead crane and refueling platform inspection provides for regular, periodic visual inspections of the reactor building crane. The protective coatings program provides for periodic visual inspections of component external surfaces. This program also provides for proper corrective actions to prevent significant degradation of the reactor building crane components due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.10, and 3.1.20 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Drywell Pneumatics System

To manage aging effects for carbon steel and stainless steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Emergency Diesel Generator System

To manage aging effects for components exposed to a demineralized water environment, the applicant relies on the following aging management programs:

- demineralized water and condensate storage tank chemistry control
- treated water systems piping inspections
- galvanic susceptibility inspections
- diesel generator maintenance activities.

The demineralized water and condensate storage tank chemistry control program serves to manage loss of material due to corrosion by limiting concentrations of impurities, total organic carbon, and conductivity. The treated water systems piping inspections comprise a one-time inspection program to validate the adequacy of the demineralized water and condensate storage tank chemistry control program in mitigating the loss of material within carbon steel and stainless steel piping. The galvanic susceptibility inspections comprise another one-time inspection program to examine carbon steel to stainless steel dissimilar metal welds to identify potential loss of material due to galvanic corrosion. The diesel generator maintenance activities are a collection of existing preventative maintenance and performance monitoring activities. These activities include inspections of emergency diesel generator components, and evaluations of the jacket water system fluid and the lubricating oil. These activities are designed to find evidence of corrosion and detect loss of heat exchanger performance. The staff's detailed review of these programs may be found in Sections 3.1.6, 3.1.24, 3.1.23, and 3.1.31 of this SER.

To manage aging effects for components in a wetted gas environment, the applicant relies on the following aging management programs:

- gas systems component inspections;
- passive component inspection activities;
- diesel generator maintenance activities.

The applicant designed both of these programs to address corrosion-related aging degradation in gas-bearing systems. The gas systems component inspections program is a new, one-time inspection program that inspects a sample of components that are considered unlikely (e.g., stainless steel components) to suffer age-related degradation. In contrast, the passive component inspection activities provide for the inspection of normally inaccessible components during maintenance activities. This latter program is for those components that are considered more likely to suffer age-related degradation. The diesel generator maintenance activities are a collection of existing preventative maintenance and performance monitoring activities. These activities include inspections of emergency diesel generator components, and evaluations of the jacket water system fluid and the lubricating oil. These activities are designed to find evidence of corrosion and detect loss of heat exchanger performance. The staff's detailed review of these programs may be found in Sections 3.1.25, 3.1.27, and 3.1.31 of this SER.

To manage aging effects for components in a moist air environment, the applicant relies on the following aging management programs:

- torque activities;
- plant coatings program;
- diesel generator maintenance activities.

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The diesel generator maintenance activities are a collection of existing preventative maintenance and performance monitoring activities. These activities include inspections of emergency diesel generator components, and evaluations of the jacket water system fluid and the lubricating oil. These activities are designed to find evidence of corrosion and detect loss of heat exchanger performance. The staff's detailed review of these programs may be found in Sections 3.1.11, 3.1.20, and 3.1.31 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

To manage aging effects for components in raw water and lubricating oil environments, the applicant relies on diesel generator maintenance activities. The diesel generator maintenance activities are a collection of existing preventative maintenance and performance monitoring activities. These activities include inspections of emergency diesel generator components, and evaluations of the jacket water system fluid and the lubricating oil. These activities are designed to find evidence of corrosion and detect loss of heat exchanger performance. The staff's detailed review of this program may be found in Section 3.1.31 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Fire Protection System

To manage aging effects for carbon steel bolting exposed to inside and outside environments, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11, and 3.1.20 of this SER.

To manage aging effects for components exposed to the various environments (inside, raw water, air, fuel oil) that exist within the fire protection system, the applicant relies on the fire protection activities program, which consists of inspection, condition monitoring and performance monitoring activities. These activities are geared for the specific environment, be it an inside, raw water, air, or fuel oil environment. The staff's detailed review of this program may be found in Section 3.1.18 of this SER.

To manage aging effects for the carbon steel tank exposed to raw water, in addition to the fire protection activities, the applicant relies on the protective coatings program, which prevents corrosion within the fire water storage tank by maintaining sufficient coating on the internal surfaces of the storage tank. The staff's detailed review of this program may be found in Section 3.1.20 of this SER.

In RAI 3.1.18-9, the staff requested that the applicant provide justification for the absence of enhanced inspection programs for the sprinkler heads, which do not have a design life that covers the period of extended operation. In response the applicant stated that, "in general, enhanced inspection programs are deemed unnecessary because the existing programs adequately manage the aging effects of concern," and that using the guidelines of the National Fire Protection Act (NFPA) Code 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection," a one-time sprinkler heads inspection is to be performed for in-scope sprinkler heads." The staff did not agree that a one-time inspection is sufficient for the sprinkler heads and recommended that the applicant expand the scope of its inspections to include the 10-year inspection intervals that are recommended in NFPA 25, Section 2.3.3.1, "Sprinklers."

The applicant has previously addressed this issue in its responses to RAIs 2.3.4-FPS-10 and 3.1.18-9. In the response to RAI 3.1.18-9 to include the 10-year inspection interval recommended in NFPA-25 for closed-head sprinklers, the applicant supplemented those earlier responses by expanding the scope of the inspections referenced. Thus, the revised commitment is to use the guidance of NFPA-25 to perform an inspection of closed head sprinklers after 50 years of service and at 10-year intervals thereafter. On the basis of the applicant's commitment, the staff finds that the applicant has adequately addressed the staff's concern and Open Item 3.1.18-1(b) is closed.

To manage aging effects for components exposed to fuel oil, in addition to fire protection activities, the applicant relies on the diesel fuel oil testing program, which samples and analyzes fuel oil deliveries for water and sediment contamination. Biocides are also added at this time in order to minimize the potential for MIC within components. Water and sediment contamination levels within storage tanks are checked on a regular basis to ensure that no significant buildup of contaminants exists. The staff's detailed review of this program may be found in Section 3.1.3 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

<u>Fuel Oil System</u>

To manage aging effects for carbon steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

To manage aging effects for components exposed to fuel oil, the applicant relies on the diesel fuel oil testing program, which samples and analzyes fuel oil deliveries for water and sediment contamination. Biocides are also added at this time in order to minimize the potential for MIC within components. The staff's detailed review of this program may be found in Section 3.1.3 of this SER.

To manage aging effects for components exposed to an air environment, the applicant uses the following aging management programs:

- gas systems component inspections
- passive component inspection activities

The applicant designed both of these programs to address corrosion-related aging degradation in gas-bearing systems. The gas systems component inspections program is a new, one-time inspection program that inspects a sample of components that are considered unlikely (e.g., stainless steel components) to suffer age-related degradation. In contrast, the passive component inspection activities provide for the inspection of normally inaccessible components during maintenance activities. This latter program is for those components that are considered more likely to suffer age-related degradation. The staff's detailed review of these programs may be found in Sections 3.1.25 and 3.1.27 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Instrument Air System

To manage aging effects for carbon steel and stainless steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Insulation System

To manage aging effects for insulation system components exposed to either an inside or outside environment, the applicant relies on the equipment and piping insulation monitoring program, which consists of visual inspections of in-scope components exposed to either an inside or outside environment. The insulation inspection looks for holes, tears, compaction, material separation, wetting, missing insulation, and general deterioration. Jackets and fasteners will also be visually inspected for loss of material and cracking. The staff's detailed review of this program may be found in Section 3.1.21 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Outside Structures HVAC System

To manage aging effects for components exposed to an air environment, the applicant relies on the following aging management programs:

- gas systems component inspections
- passive component inspection activities

The applicant designed both of these programs to address corrosion-related aging degradation in gas-bearing systems. The gas systems component inspections program is a new, one-time inspection program that inspects a sample of components that are considered unlikely (e.g., stainless steel components) to suffer age-related degradation. In contrast, the passive component inspection activities provide for the inspection of normally inaccessible components during maintenance activities. This latter program is for those components that are considered more likely to suffer age-related degradation. The staff's detailed review of these programs may be found in Sections 3.1.25 and 3.1.27 of this SER.

To manage aging effects for carbon and stainless steel bolting exposed to inside and outside environments, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

<u>Plant Service Water System</u>

To manage aging effects for components exposed to a raw water environment, the applicant relies on the following aging management programs:

- plant service water and residual heat removal service water inspection program
- plant service water and residual heat removal service water chemistry control program
- galvanic susceptibility inspections

The plant service water and residual heat removal service water inspection program is a condition monitoring program designed to detect wall thickness degradation or fouling in the plant service water and residual heat removal service systems. The plant service water and residual heat removal service water chemistry control program mitigates aging in system piping and components by controlling fluid composition through treatment with sodium hypochlorite and sodium bromide. The aging effects of plant service water system carbon steel components in the river water environment are further managed by the galvanic susceptibility inspections. These are one-time inspections to provide objective evidence that galvanic susceptibility is being managed for specific components within the scope of license renewal. The staff's detailed review of these programs may be found in Sections 3.1.13, 3.1.4, 3.1.22, and 3.1.23 of this SER.

To manage aging effects for carbon steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program will also provide for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

To manage aging effects for the carbon steel pump sub-base externally exposed to an inside environment, the applicant relies on the following aging management program:

- protective coatings program

The protective coatings program provides for periodic inspection of component external surfaces, including the carbon steel pump sub-base. This program will also provide for proper corrective actions to prevent significant degradation of the sub-base due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of this program may be found in Section 3.1.20 of this SER.

The staff conducted a scoping inspection in the offices of SNC from September 11, 2000 through September 15, 2000. The results of the inspection are documented in Inspection Report 50-321/00-09, 50-366/00-09. During the inspection, the inspectors identified a guard pipe associated with the Division I plant service water piping in the diesel generator building. This guard pipe had not been considered for scoping and screening in the LRA. In response to this inspection finding, the applicant evaluated the guard pipe and concluded that it did not perform an intended function, and therefore was not within the scope of license renewal. The staff agreed with this conclusion. The staff's review of the applicant's evaluation of the guard pipe can be found in Section 2.3.4.13 of this SER. The internal surface of the PSW piping is exposed to raw water, and thus the aging effects and aging management programs are consistent with other piping sections in this system. However, the portion of the PSW piping surrounded by the guard pipe is welded to the guard pipe at both ends. Thus, the external surface of this section of plant service water piping is not easily accessible for inspection. The applicant plans to perform a one-time inspection to assess the material condition of the external surfaces of this piping section. The one-time inspection is discussed in Section 3.1.13 of this SER.

In RAI 3.4-9, dated July 28, 2000, the staff noted that the applicant stated in the LRA that selective leaching was a corrosion mechanism that may result in loss of material for brass and gray cast iron components exposed to a raw water environment in the plant service water and fire protection systems. Given that selective leaching may not be detectable through standard visual inspections, the staff asked the applicant to discuss how the various inspection and testing programs are adequate to manage the aging effect (loss of material) resulting from this aging mechanism. In its October 10, 2000 response, the applicant stated that no age-related failures were identified for these components in the plant's operating history. In addition, for susceptible components in the fire protection system, the components' functionality is closely linked to performance characteristics that are currently monitored though fire protection activities. The staff agrees that the fire protection activities provide reasonable assurance of component functionality. For susceptible components in the plant service water system, the applicant committed to additional activity. The applicant provided additional information regarding this activity in its letter dated January 31, 2001. The applicant will either perform a Brinell hardness test, or a metallurgical analysis, on one plant service water component from each commodity (brass and gray cast iron) in existence at Plant Hatch within the time frame of August 6, 2009 to August 6, 2014 for Unit 1, and June 13, 2013 and June 13, 2018 for Unit 2. The results will be compared to the design code of record as well as available textbook and vendor data. The scope and timing of the activity appear to the staff to be reasonable, given that selective leaching has not been identified at Plant Hatch. Also, the staff agrees that Brinell hardness testing and metallurgical analysis are both widely acceptable means of determining if selective leaching is occurring. The acceptance criteria are reasonable and consistent with staff expectations and current industry practice. In summary, the staff finds the applicant's stated approach satisfactory to manage selective leaching for components in the plant service water system. The applicant incorporated a one-time inspection into the PSW and RHRSW inspection program.

On the basis is the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Primary Containment Chilled Water System (Unit 2 Only)

To manage aging effects for carbon steel, stainless steel, and copper alloy components exposed internally to the closed cooling water environment, the applicant relies on the following aging management programs:

- closed cooling water chemistry control
- treated water systems piping inspection

The closed cooling water chemistry control program is a mitigating activity intended to maintain structural integrity of plant closed cooling water systems and components by controlling fluid purity and composition. The treated water systems piping inspections program supplements the chemistry control program. It is a new program consisting of a one-time inspection to provide direct evidence that the existing chemistry control program is managing aging in piping that is not examined under other inspection programs. The staff's detailed review of these programs may be found in Sections 3.1.2 and 3.1.24 of this SER.

To manage the aging effects of the carbon steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Reactor Building Closed Cooling Water System

To manage aging effects for carbon steel, stainless steel, and copper alloy components exposed internally to the closed cooling water environment, the applicant relies on the following aging management programs:

- closed cooling water chemistry control
- treated water systems piping inspection

The closed cooling water chemistry control program is a mitigating activity that is intended to maintain the structural integrity of plant closed cooling water systems and components by controlling fluid purity and composition. The treated water systems piping inspections program supplements the chemistry control program. It is a new program consisting of a one-time inspection to provide direct evidence that the existing chemistry control program is managing aging in piping that is not examined under other inspection programs. The staff's detailed review of these programs may be found in Sections 3.1.2 and 3.1.24 of this SER.

To manage aging effects for carbon steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Reactor Building HVAC System

To manage aging effects for components exposed to an air environment, the applicant relies on the gas systems component inspections program, which is a new, one-time inspection program that visually inspects a sample of components that are considered unlikely to suffer age-related degradation. The staff's detailed review of this program may be found in Section 3.1.25 of this SER.

To manage aging effects for carbon steel bolting exposed to inside and outside environments, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Refueling Equipment System

To manage aging effects for components exposed to an inside environment, the applicant relies on the following aging management programs:

- protective coatings program
- overhead crane and refueling platform inspection

The protective coatings program provides for periodic inspection of component surfaces. This program also provides for proper corrective actions to prevent significant degradation (e.g., replacement or coating of exposed surfaces). The overhead and refueling platform crane inspection program provides for visual inspection and testing of the reactor building overhead cranes and crane rail supports and refueling platform to assure safe operation of the crane. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.10 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Sampling System

To manage aging effects for components exposed to a wetted gas environment, the applicant relies on the gas systems component inspections program, which is a new, one-time inspection program that inspects a sample of components from several gas systems within the scope of license renewal to provide evidence that the aging effects predicted for systems with gases as internal environments are being adequately managed. The staff's detailed review of this program may be found in Section 3.1.25 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Tornado Vents System

To manage aging effects for the acrylic components exposed to an inside and outside environment, the applicant relies on the structural monitoring program, which visually inspects structural components on a regular, periodic basis. The staff's detailed review of this program may be found in Section 3.1.22 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Traveling Water Screens/Trash Rack System

To manage aging effects for the carbon and stainless steel components submerged in or exposed to a raw water environment, the applicant relies on the following aging management programs:

- structural monitoring program
- protective coatings program

The structural monitoring program provides for visual inspection of structural components on a regular, periodic basis. The protective coatings program provides for periodic visual inspections of component external surfaces. This program also provides for proper corrective actions to prevent significant degradation of the traveling water screens and trash rack components due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.22 and 3.1.20 of this SER.

To manage aging effects for carbon steel valve bodies exposed to raw water, the applicant identified the following aging management programs:

- plant service water and residual heat removal service water inspection program
- plant service water and residual heat removal service water chemistry control program
- galvanic susceptibility inspections

The plant service water and residual heat removal service water inspection program is a condition monitoring program designed to detect wall thickness degradation or fouling in the plant service water and residual heat removal service water systems. The plant service water and residual heat removal service water chemistry control program mitigates aging in system piping and components by controlling fluid composition through treatment with sodium hypochlorite and sodium bromide. The aging effects of plant service water system carbon steel components in the river water environment are further managed by the galvanic susceptibility inspections. These are one-time inspections to provide objective evidence that galvanic susceptibility is being managed for specific components within the scope of license renewal. The staff's detailed review of these programs may be found in Sections 3.1.13, 3.1.4, and 3.1.23 of this SER.

To manage aging effects for carbon steel bolting exposed to an outside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Summary - Aging Management Programs

The staff has reviewed the information presented by the applicant regarding aging management programs credited for managing the aging effects associated with the commodity groups within the auxiliary systems. On the basis of this information, the staff concludes that the applicant has aging management programs which will manage the aging effects for the commodity groups in the auxiliary systems for the period of extended operation.

3.4.4 Conclusion

The staff has reviewed the information for the auxiliary systems in Section 3.2.4, "Auxiliary Systems," Section C.1, "Evaluation of Aging Effects Requiring Management," Section C.2, "Aging Management Reviews," and Section A, "Final Safety Analysis Report Supplement" of the LRA, as supplemented by Section B of submittal dated October 10, 2000. On the basis of this review, the staff concludes that the applicant has identified the aging effects associated with the auxiliary systems and has demonstrated that the aging effects will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the current licensing basis during the period of extended operation.

3.5 Steam and Power Conversion Systems

3.5.1 Introduction

The applicant described its AMR for the steam and power conversion systems (SPCS) for license renewal in Sections 3.2.5 "Steam and Power Conversion" of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the SPCSs will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

External environments are defined in Sections C.1.2.8, "Inside;" C.1.2.9, "Outside;" and C.1.2.10, "Buried or Embedded" of the LRA. "Inside" external environments are defined as environments where equipment is sheltered from the weather. "Outside" external environments are defined as environments found outside a structure where equipment would not be sheltered from the weather. "Buried or embedded" external environments are defined as environments beneath the surface of the ground (in some cases with controlled backfill) or embedded in structural concrete. Structures and components which perform their functions in external environments are, in general, discussed in Sections 3.2, 3.3, 3.4, 3.5, 3.6, and 3.7 of the LRA, and are evaluated in Sections 3.6 and 3.7 of this SER, unless otherwise noted.

3.5.2 Summary of Technical Information in the Application

The SPCSs included within the AMR scope comprise the electro-hydraulic control (EHC) system and the main condenser system (Unit 2 only).

3.5.2.1 Aging Effects

Electro-Hydraulic Control System

The purpose of the EHC system is to provide control of reactor pressure during reactor startup, power operation, and shutdown. The EHC system also provides a means of controlling main turbine speed and acceleration during turbine startup, and protects the main turbine from undesirable operating conditions by initiating alarms, trips, and runbacks. As described in LRA Section 2.1.2, the initial scoping was performed on the basis of functions. The intended function is associated with the main turbine pressure regulators, whereby the turbine control valve position is controlled by adjusting EHC pressure based on main steam pressure. The EHC regulators that are within the scope of license renewal are 1N11-N042A/B and 2N32-N301A/B. Technical specifications do not require the regulators to be operable; however, transient analysis takes credit for the backup pressure regulator to function to prevent fuel damage in the event of a downscale failure of the inservice regulator.

Materials of construction for the components supporting the EHC intended function are stainless steel piping and stainless steel valve bodies in a reactor water environment. The aging effects associated with this commodity group are loss of material and cracking.

Main Condenser System (Unit 2 Only)

The main condenser provides a heat sink for turbine exhaust steam, turbine bypass steam, and other flows (such as cascading heater drains, air ejector condenser drains, exhaust from the feed pump turbines, gland seal condenser, feedwater heater shell operating vents, and condensate pump suction vents). The main condenser also deaerates and provides storage capacity for the condensate water to be reused. The main condenser system is a two-shell, single-pass, divided water box, deaerating type designed for condenser duty of 5.66 x 10^9 Btu/h, an inlet water temperature of 90 °F, and an average backpressure of 3.5 in. Hg absolute. During plant operation, steam from the last-stage, low-pressure turbine is exhausted directly downward into the condenser shells through exhaust openings in the bottom of the turbine casings. The condenser serves as a heat sink for several other flows, such as exhaust steam from the feed pump turbines, cascading heater drains, air ejector condenser drain, gland-seal condenser drain, feedwater heater shell operating vents, and condensate pump suction vents. Other flows occur periodically. These originate from condensate and reactor feed pump startup vents, reactor feed pump minimum recirculation flow, feedwater lines startup flushing, turbine equipment clean drains, low-point drains, extraction steam spills, makeup, and condensate. During abnormal conditions, the condenser is designed to receive (not simultaneously) turbine bypass steam, feedwater heater high-level dumps, and relief valve discharge from feedwater heater shells, steam-seal regulator, and various steam supply lines.

As described in LRA Section 2.1.2, the initial scoping was performed on the basis of functions. Post-accident radioactive decay holdup is the intended function associated with this system.

The post-accident radioactive decay holdup provides a method for MSIV leakage control. It uses the main steam drain lines to convey the MSIV leakage during post-accident conditions to the isolated main condenser. The main condenser provides holdup and allows "plate-out" of the fission products that may leak from the closed MSIV during post-accident conditions. MSIV leakage that enters the condenser is ultimately released to the turbine building as non-condensible gases through the low pressure turbine seal after significant plate-out of iodine.

Materials of construction for the components supporting the intended functions of the main condenser are carbon steel for bolting, condenser shell, piping, preheater, strainer, and valve bodies, and stainless steel for piping, preheater, restricting orifices, thermowells, and valve bodies. All components, except bolting, are exposed to a reactor water environment. The aging effects associated with these commodity groups are loss of material and cracking.

3.5.2.2 Aging Management Programs

The LRA identified the following six aging management programs that will manage the aging effects associated with the steam and power conversion systems:

- reactor water chemistry control
- treated water systems piping inspections
- galvanic susceptibility inspections
- flow-accelerated corrosion program
- protective coating program
- torque activities

Detailed descriptions of these aging management programs are included in Section A of the LRA.

Reactor water chemistry control is a major part of the overall chemical control strategy for Plant Hatch. It is a mitigating activity designed to maintain structural integrity of plant systems and components by controlling fluid purity and composition. Treated water systems piping inspections will provide for condition monitoring via one-time examinations intended to provide objective evidence that existing chemistry control is managing aging in piping that is not examined under another inspection program. Galvanic susceptibility inspections will provide for condition monitoring via one-time inspections that will provide objective evidence that galvanic susceptibility is being managed for specific components within the scope of license renewal. The FAC program is a condition monitoring program designed to monitor pipe wear in those systems that have been determined to be susceptible to FAC-related loss of material. The protective coatings program provides a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the associated environment. It is a mitigation and condition monitoring program designed to provide base metal aging management through application, maintenance, and inspection of protective coatings in selected components and structures. Torque activities are intended to mitigate loss of preload through use of proper torque techniques.

3.5.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.2.5 of the LRA to determine whether the applicant has identified the aging effects associated with the SPCS, and has demonstrated that the effects of aging on the SPCS will be adequately managed during the period of extended operation.

3.5.3.1 Effects of Aging

The SPCS components are constructed from carbon steel and stainless steel. They are exposed to an external environment of air in the turbine building, which by itself will not cause any significant aging effects. Internally, the SPCS components are exposed to a treated water and/or steam environment. The material degradation effects that were identified in the systems carrying treated water and steam include loss of material, cracking, and loss of preload in bolting. Tables 3.2.5-1 and 3.2.5-2 of the LRA list the components, component functions, materials, environments, applicable aging effects, and the applicable AMPs.

The applicant supplied references to plant-specific and industry-wide experience to support its identification of applicable aging effects for steam and power conversion systems. On the basis of the description of the internal and external environments and materials of fabrication for these systems, the staff concludes that the applicant has identified aging effects that are consistent with published literature and industry experience and, thus, are acceptable to the staff.

3.5.3.2 Aging Management Programs

The applicant has identified six aging management programs for controlling the effects of aging in the SPCS:

- reactor water chemistry control
- treated water systems piping inspections
- galvanic susceptibility inspections
- flow accelerated corrosion program
- protective coating program
- torque activities

The staff's evaluation of these aging management programs is discussed in Section 3.1 of this SER.

The programs were developed from industry-wide data, industry-developed methodologies, NRC documents, and the applicant's own experience. The applicant concluded that these programs would manage the aging effects in such a way that the functions of the SPCS components will be maintained during the period of extended operation, in a manner that is consistent with the CLB, under all design conditions.

In LRA Tables C.2.2.1-1 and C.2.2.1-2, the applicant lists the following 10 attributes that each aging management program and activity required to address:

- scope of programs, which includes the specific structure, component, or commodity for the identified aging effect

- preventive actions to mitigate or prevent aging degradation
- linkage of parameters monitored or inspected to the degradation of the particular intended function
- description and timely performance of the method used to detect aging effects
- monitoring and trending for timely corrective actions
- acceptance criteria
- corrective actions, including root cause determination and prevention of recurrence
- confirmation process
- administrative controls, which provide a formal review and approval process
- consideration of operating experience from the AMP, including past corrective actions that resulted in program enhancements or additional programs

The staff evaluated the applicant's aging management programs in order to determine if they are adequate to manage the aging of the SPCS components so that the components will perform their intended functions in accordance with the CLB during the period of extended operation. On the basis of the information provided in the LRA and the applicant's responses to the staff's RAIs, the staff concludes that the aging management programs that the applicant credits for managing the aging effects associated with the SPCS will manage the aging effects such that the SPCS components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5.4 Conclusions

The staff has reviewed the information in Section 3.2.5 of the LRA. On the basis of this review, the staff concludes that the applicant has identified the aging effects associated with the SPCS and has demonstrated that aging effects will be adequately managed so that there is a reasonable assurance that the SPCS components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.6 Structures and Structural Components

3.6.1 Introduction

The applicant described its AMR of the structures and structural components for license renewal in the following sections of the LRA: Section 2.4, "Structures Screening Results," Section 3.3.1, "Civil Structural Components," Section A.1, "Existing Programs and Activities," Section A.2, "Enhanced Programs and Activities," Section A.3, "New Programs and Activities," and Section C.2.6, "Aging Management Review for Civil Discipline Commodities." The staff reviewed these sections and appendices of the LRA to determine whether the applicant has demonstrated that the effects of aging on the structures and structural components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.2 Summary of Technical Information in the Application

3.6.2.1 Effects of Aging

Section 2.4 of the Plant Hatch LRA provides a list of the various civil/structural component groups that are subject to an aging management review. For each of the civil/structural component groups in Section 2.4 of the LRA, the applicant also provided a general description of the structure or system and intended functions associated with each structure or system. Section C.1 of the LRA describes the applicant's approach toward identifying, categorizing, and evaluating plant environments and materials and the resulting aging effects applicable to systems, structures, and components determined to require aging management reviews. The applicant has adopted a commodities approach to evaluating aging effects requiring management and aging management programs. Section 3.0 of the LRA provides a discussion of the process used to develop the commodity groups. Once systems, structures, and components were divided into commodity groups, an analysis of the aging effects requiring management was performed.

Civil/structural component evaluations are discussed in Section C.2.6 of the LRA , and are based on material of construction.

Environments, aging effects requiring management, and associated aging mechanisms are discussed in Section C.1.4 of the LRA under each material of construction. Determination of the aging effects requiring management for each of these groups is presented in sections C.1.4.1 through C.1.4.4 of the LRA.

External environments are defined in Sections C.1.2.8, "Inside;" C.1.2.9, "Outside;" and C.1.2.10, "Buried or Embedded" of the LRA. "Inside" external environments are defined as environments where equipment is sheltered from the weather. "Outside" external environments are defined as environments found outside a structure where equipment would not be sheltered from the weather. "Buried or embedded" external environments are defined as environments beneath the surface of the ground (in some cases with controlled backfill) or embedded in structural concrete. Structures and components which perform their functions in external environments are, in general, discussed in Sections 3.2, 3.3, and 3.4 of the LRA, and are evaluated in Sections 3.6 and 3.7 of this SER, unless otherwise noted.

Summaries of aging effects, determined by the applicant as applicable to each of the civil/structural component groups listed in Section 3.6.2.1 of this SER, are provided in Tables 3.3.1-1 through 3.3.1-13 of the LRA.

A brief description of each of the civil/structural component groups and their applicable aging effects is provided in the following sections.

<u>Conduits, Raceways, and Trays</u>

The purpose of the conduits, raceways, and trays system is to provide support for a cable system with cables and penetrations selected, routed, and located to survive the design-basis events established for the plant and to prevent a loss of function of any system due to a cable failure. Additional information may be found in Unit 1 UFSAR Section 8.8 and Unit 2 UFSAR Section 8.3.

The conduits, raceways, and trays that are mounted according to Seismic Category I criteria are considered safety-related. Seismic Category I conduits, raceways, and trays provide support for essential cable feeding power supplies and controls.

The conduits, raceways, and trays that are neither mounted as Seismic Category I nor Seismic Category II/I are considered non-safety-related. Non safety-related conduits, raceways, and trays provide support for non-essential cable feeding power supplies and controls. Also, some non-seismic raceways are included in safe shutdown pathways.

The applicant identified loss of material as the applicable aging effect for cable trays and supports made of carbon steel.

Control Building

The purpose of the control building is to house the common control room for Units 1 and 2 and associated auxiliaries. The building is a reinforced concrete structure with steel framing, and consists of the following major structural components:

- reinforced concrete foundation mat
- reinforced concrete floors with reinforced concrete beam and girder framing
- reinforced concrete or concrete block interior walls and reinforced concrete columns
- reinforced concrete exterior walls and prestressed exterior wall panels
- reinforced concrete slab on metal roof deck system supported by steel framing

Additional information may be found in Unit 1 UFSAR Section 12.3.3.1.1 and Unit 2 UFSAR Section 3.2.1.

The control building includes the substructure, foundations, superstructure, walls, floors, and roof necessary to maintain equipment integrity and personnel habitability. The control building is designed as a Seismic Category I structure to protect vital equipment and systems both during and following the most severe natural phenomenon.

The applicable aging effects for structural components in the control building are loss of material and cracking.

Drywell Penetrations

Table 3.3.1-3 of the LRA identifies the containment mechanical penetrations and steel bellows inside vent pipe as components requiring aging management. The function of the containment mechanical penetrations is that of a "fission product barrier," and that of the bellows is to provide a "pressure boundary and fission product barrier." Their environment is the inside atmosphere of containment. Table 3.3.1-3 refers to Section C.2.6.2 of the LRA for a description of the aging management review. Mechanical penetrations are discussed in Section 2.4.3 of the LRA.

The purpose of the drywell electrical penetrations is to provide a path for cable currents/signals to pass through primary containment to support the various modes of operation of their associated systems while maintaining the integrity of the primary containment.

Containment penetrations include electrical penetration assemblies in addition to the mechanical penetrations referenced above. Electrical penetrations are hermetically sealed penetrations, which are welded to the primary containment shell plate. They must maintain their primary containment pressure integrity function during all postulated operating and accident conditions. They are designed for the same pressure and temperature conditions as the drywell and pressure suppression chamber.

The applicant identified loss of material as the applicable aging effect for drywell penetrations.

Emergency Diesel Generator (EDG) Building

The purpose of the EDG building is to house the emergency diesel generators and their accessories essential for safe plant shutdown for both Unit 1 and Unit 2. The EDG building is a reinforced concrete structure consisting of the following major structural components:

- reinforced concrete foundation mat
- reinforced concrete exterior walls and interior walls
- reinforced concrete roof and parapet wall

The EDG building houses EDGs and their accessories and the building has labyrinth access openings for protection against tornado missiles. The EDG building is designed as a Seismic Category I structure to protect vital equipment and systems both during and following the most severe natural phenomena. The EDG building provides support and equipment integrity for the EDGs, which provide essential ac supply. Additional information may be found in Unit 1 UFSAR Section 12.2.6 and Unit 2 UFSAR Section 9.4.5.

The applicant identified loss of material as the applicable aging effect for structural components in the EDG building.

Fuel Storage

The fuel storage system provides specially designed underwater storage space for the spent-fuel assemblies, which require shielding and cooling during storage and handling. This system also provides specially designed dry, clean storage areas for the new fuel assemblies. The fuel storage facility is located inside the secondary containment on the refueling floor.

The components included in the fuel storage facility are the spent fuel pool, concrete vault and stainless steel liner, fuel pool gates, fuel racks, and other equipment necessary to properly store irradiated fuel and components.

The fuel storage system contains components fabricated from carbon steel, stainless steel, aluminum, and concrete, that are exposed to an inside and demin water environment.

Additional information may be found in Sections 10.2 and 10.3 of the Unit 1 UFSAR, and Section 9.1 of the Unit 2 UFSAR.

The applicant identified loss of material as the applicable aging effect for fuel storage components.

Intake Structure

The purpose of the intake structure is to protect residual heat removal service water and plant service water equipment from the influence of environmental conditions such as flooding, earthquakes, and tornadoes.

The intake structure is a concrete and steel structure consisting of the following major structural components:

- reinforced concrete foundation mat
- reinforced concrete exterior walls and internal walls
- reinforced concrete floors and roof
- structural steel framing and grating, steel water spray and internal missile shield barriers, stairs, and platforms

Unit 1 shares the intake structure with Unit 2. The intake structure has labyrinth access openings for protection against tornado missiles. Additional information may be found in Unit 1 UFSAR Subsection 12.2.7 and Unit 2 UFSAR Subsection 3.8.4.

The applicant identified loss of material as the applicable aging effect for structural components in the intake structure.

Main Stack

The purpose of the main stack is to support and protect monitoring equipment and provide for the monitoring and elevated release of gaseous effluents from the main stack system.

The main stack is a concrete cylindrical shape, which consists of the following major components:

- reinforced concrete foundation mat supported on steel "H" piles
- reinforced concrete truncated conical cylinder
- reinforced concrete internal floors
- reinforced concrete loading bay consisting of concrete base slab, external and internal walls, and roof

Unit 1 shares a single main stack used to discharge gaseous waste with Unit 2. The main stack extends 120 meters above ground level. Additional information may be found in Unit 1 UFSAR subsection 5.3.4 and Unit 2 UFSAR Section 11.3.

The applicant identified loss of material and cracking as the applicable aging effects for structural components of the main stack.

Piping Specialties

The applicant stated that piping specialties provide support for essential piping systems. Essential piping systems are required to maintain the integrity of safety-related and non safety-related systems during normal operations and for transient/accident mitigation. The piping specialties consist of hangers and supports for ASME Class I piping; hangers and supports for non-ASME Class I piping, tubing, and ducts; and tube trays and covers. These piping specialties also include snubbers and pipe restraints, regardless of system affiliation, as well as non-ASME HVAC duct supports and tube trays. The applicant stated that pipe supports for the reactor coolant system and subsystems are provided to ensure pressure retaining capability of the piping systems against weight, seismic, and fluid dynamic loads. Pipe supports maintain the integrity of non safety functions during accident and seismic events. This includes all safety-related plant pipe supports, pipe restraints, and tubing supports. Pipe supports for non safety-related piping (non seismic category) located throughout the plant are included in this function. These supports are not designed to any seismic criteria. but are designed for dead weight and thermal loads only. Only those Seismic Category II supports required to support functions X43-04 (Plant Wide Fire Suppression With Water), W33-03 (Screen Wash Isolation), and N61-03 (Post-Accident Radioactive Decay Holdup) are included within the scope of license renewal. All other Seismic Category II supports are excluded from the scope of license renewal.

In Table 3.3.1-1 of the LRA, the applicant listed the structural components, environments in which the components are located, materials of construction, applicable aging effects, and aging management programs for the components associated with piping specialties. The piping specialties consist of hangers and supports for ASME Class I piping, hangers and supports for non-ASME Class I piping, tubing, and ducts, as well as tube trays and covers exposed to containment atmosphere, inside (sheltered), outside, and submerged environments. These components are made of carbon, galvanized, and stainless steels.

Loss of material is identified as the applicable aging effect for piping specialty components.

Primary Containment

The purpose of the primary containment is to isolate and contain fission products released from the reactor primary system following a DBA and to confine the postulated release of radioactive material.

The primary containment design employs a pressure suppression containment system, which houses the reactor vessel, the reactor coolant recirculating loops, and other branch connections of the reactor primary system. The pressure suppression system consists of a drywell; a pressure suppression chamber (torus), which stores a large volume of water; a connecting vent system between the drywell and the pressure suppression pool, isolation valves, vacuum relief system; containment cooling systems; and other service equipment. The pressure suppression chamber is a steel pressure vessel, in the shape of a torus located below and encircling the drywell, with a major diameter of approximately 107 ft and a cross-sectional diameter of approximately 28 ft. The pressure suppression chamber contains the suppression pool and the air space above the pool. The suppression chamber transmits seismic loading to the reinforced concrete foundation slab of the reactor building. Space is provided outside of the chamber for inspection. Additional information about this system may be found in Unit 1 UFSAR Subsection 5.1.2 and Unit 2 UFSAR Subsection 6.2.1

The primary containment system, in conjunction with other safeguard features, provides the capability to limit the release of fission products in the event of a postulated DBA so that offsite doses do no exceed 10 CFR Part 100 guidelines. The pressure suppression pool initially serves as a heat sink for any postulated transient or accident condition in which the normal heat sink (main condenser or shutdown cooling system) is unavailable.

Loss of material and cracking are identified as the applicable aging effects for structural components in the primary containment.

Reactor Building

The purpose of the reactor building is to shelter and support the refueling and reactor servicing equipment, new and spent fuel storage facilities, and other reactor auxiliary and service equipment.

The building is a reinforced concrete structure with a steel superstructure. The building consists of the following major structural components:

- reinforced concrete foundation mat
- reinforced concrete exterior walls and precast exterior wall panels
- reinforced concrete floors with reinforced concrete beams and girders framing
- reinforced concrete interior walls with some blockouts filled with concrete masonry
- reinforced concrete roof slab on metal roof deck system supported by steel superstructure

The reactor building completely encloses the reactor and its pressure suppression primary containment system. Also housed within the reactor building are the core standby cooling systems, RWCU demineralizer system, SLCS, CRD system, RPS, and electrical equipment components. The building is designed for minimum leakage so that the SGTS has the necessary capacity to reduce and hold the building at a subatmospheric pressure under normal wind conditions. Additional information may be found in Unit 1 UFSAR Subsection 12.2.1 and Unit 2 UFSAR Section 3.0.

The reactor building provides primary containment during reactor refueling and maintenance operations when the primary containment is open. It also provides an additional barrier when the primary containment system is functional. Therefore, it is relied on to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the 10 CFR Part 100 guidelines. This evaluation includes the blowout panels in the pipe-chase between the reactor building and the turbine building.

Loss of material, cracking, material property changes, and loss of adhesion are identified as the applicable aging effects for structural components in the reactor building.

Reactor Building Penetrations

The purpose of the reactor building penetrations is to allow mechanical and electrical equipment and personnel to pass through secondary containment and support the various modes of operation of their associated systems while maintaining the integrity of the secondary containment. The penetrations for piping and ducts are designed for leakage characteristics consistent with containment requirements for the entire building. Electrical cables and instrument leads pass through ducts sealed into the building wall.

Table 3.3.1-7 of the LRA identifies the reactor building penetrations as components requiring aging management. The reactor building penetrations function as a "fission product barrier." The penetration materials are carbon steel and galvanized steel functioning in inside, outside, and embedded environments. Section C.2.6.3 of the LRA contains the aging management review for steel structures in seismic Category I buildings. Table 3.3.1-7 identifies the protective coating program and the structural monitoring program as the AMPs credited with managing the aging effects for reactor building penetration components. Additional information may be found in Unit 1 UFSAR Section 5.3.3.2 and Unit 2 UFSAR Figure 8.3-11.

The applicant identified loss of material as the applicable aging effect for reactor building penetration components.

Turbine Building

The purpose of the turbine building is to house the turbine-generator and associated auxiliaries, including the condensate and feedwater systems.

The turbine building is a steel and concrete structure consisting of the following major structural components:

- reinforced concrete foundation mat
- reinforced concrete floors self-supporting or supported by structural steel framing
- reinforced concrete or concrete block interior walls
- reinforced concrete turbine pedestal resting on concrete mat foundation
- reinforced concrete exterior walls
- reinforced concrete slab on metal roof deck system supported by steel framing

Additional information may be found in Unit 1 UFSAR Section 12.2.2 and Unit 2 UFSAR Section 3.2.

There is no equipment or instrumentation located in the turbine building proper that would preclude the ability to shut down the reactor safely if the turbine building were damaged from a high-energy line failure. The turbine building is designed and constructed to ensure that it will not damage Category I structures or equipment located inside or adjacent to it in the event of a design-basis event (DBE). The cable chase area below elevation 147 ft is designed to Seismic Category I criteria. The Seismic Category I barrier between the main steam and feedwater piping located above elevation 147 ft and the cable chase area below precludes any adverse direct effects of postulated failure of the main steam or feedwater piping in the turbine building. The cables in this area provide trip inputs for the recirculation pump trip and reactor scram following generator load rejection or a turbine trip originating in the turbine building. Based on these considerations, the portions of the Unit 1 turbine building and the cable chase area below elevation 147 ft are included within the scope of license renewal. The portions of the Unit 2 turbine building and the cable chase area below elevation 147 ft are also in scope, as well as the supports over the radioactive release pathway for the main condenser.

Loss of material is identified as the applicable aging effect for structural components in the turbine building.

Yard Structures

The purpose of the yard structures is to provide equipment integrity and personnel habitability for various structures on the plant site. These yard structures include:

- concrete wall and foundation accommodating the condensate storage tank
- foundation of the nitrogen storage tank
- service water valve pit boxes
- foundation for the fire pump house
- foundations for the two fire protection water storage tanks
- foundations for the two fire protection diesel pump fuel tanks
- underground concrete duct runs and pull boxes between Class I structures

Additional information about these structures may be found in Unit 1 UFSAR Section 5.2.3.9 and Unit 2 UFSAR Section 3.8.5.1.

The intended function of the yard structures is to provide equipment integrity and personnel habitability for the various structures listed. This intended function is brought into scope because of the Seismic Category I foundation supporting the liquid nitrogen tank. The liquid nitrogen tank provides the safety-related backup supply of motive gas for the drywell inerting system and the drywell pneumatic system. The UFSAR discusses the reliance of the safety analysis upon the liquid nitrogen tank. In addition, Safe Shutdown Pathways 1 and 2 in the FHA rely upon the liquid nitrogen tank to achieve safe shutdown in the event of a fire.

With respect to the enclosure around the CST, the wall and the CST foundation are seismically qualified to Category 1 requirements. The service water valve boxes are in scope as they contain in-scope piping for the plant service water system. The concrete duct runs and pull boxes that traverse the yard between various Class I structures as well as turbine building are included within the scope of AMR. These duct runs are used for routing safety-related circuits and provide protection to them.

The foundations for the fire pump house, fire protection water storage tanks, and the fire protection diesel pump fuel tanks are also in scope.

Loss of material is identified as the applicable aging effect for structural components in yard structures.

3.6.2.2 Aging Management Programs

The program and activity descriptions presented in Sections A and B of the LRA represent the commitments for managing aging of the in-scope systems, structures and components during the period of extended operation. Eleven aging management programs or activities are credited for managing the applicable aging effects for civil/structural components during the renewal term. In many cases, existing programs and activities were found adequate for managing aging in the renewal term. In some cases, aging management reviews revealed that programs or activities required some degree of enhancement to adequately manage aging. Lastly, a number of new inspection programs have been developed by the applicant to provide objective evidence that aging was, in fact, being adequately managed by the credited programs and activities. The scope of these programs and activities for license renewal is discussed in Sections A and B of the LRA.

In Tables 3.3.1-1 through 3.3.1-13 of the LRA, the applicant identified the following aging management programs and activities required to manage aging effects for specific civil/structural component groups discussed in Section 3.6.2.1 of this SER:

- protective coatings program
- structural monitoring program
- inservice inspection program
- suppression pool chemistry control program
- demineralized water and condensate storage tank chemistry control program
- treated water systems piping inspections
- passive component inspection activities
- gas systems component inspections
- primary containment leakage rate testing program
- component cyclic or transient limit program
- fuel pool chemistry control program

3.6.3 Staff Evaluation

The staff reviewed the information provided in Section 2.4, "Structures Screening Results," and Section 3.3.1, "Civil/Structural Components," of the Plant Hatch LRA, and pertinent information provided in Sections A, B, and C of the LRA to determine whether the applicant has adequately identified the effects of aging on the structures and structural components listed in Section 3.6.2.1 of this SER and whether the applicant has demonstrated that the associated components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). After completing the initial review, the staff issued several requests for additional information that are discussed within the context of the staff evaluation below.

3.6.3.1 Effects of Aging

The applicant stated that the process to determine the aging effects applicable to structural components begins with a review of the aging effects identified in industry literature. Section C.1 of the LRA presented The applicant's systematic evaluation of environments and materials to identify those aging effects requiring management in the renewal term. This evaluation was performed using information developed based on available industry knowledge. A review of pertinent generic industry operating experience, as contained in NRC generic communications, was a part of the applicant's process for determining aging effects requiring management. Generic communications evaluated as part of this review are listed in Table C.1.5-1 of the LRA and the results are contained in the sections for various material and environment combinations at Plant Hatch. The staff finds this approach for reviewing industry operating experience acceptable.

From this set of aging effects, the applicant considered Plant Hatch materials, operating environment (internal and external) and operating stresses to determine aging effects that need to be managed. Finally, the plant-specific operating experience, industry-wide operating experience and CLB are reviewed to identify any additional aging effects that require aging management. The applicant indicated that this process should provide reasonable assurance that the full set of aging effects was established for the aging management review. The staff concurs with this approach for identifying pertinent aging effects.

GENERAL STRUCTURAL AGING EFFECTS

In order to facilitate the identification of aging effects requiring management, the applicant categorized Plant Hatch structural components into the following groups:

- structural steel and aluminum components
- concrete components
- structural sealants
- acrylic

A discussion of the aging effects requiring management for each of these groups follows.

<u>Structural Steel and Aluminum Components</u>

The applicant grouped structural steel and aluminum components into commodities to efficiently perform the aging management reviews. Details of these reviews are described in Section C.2.6 of the LRA. The component types that make up the commodity groups were collectively reviewed by the applicant. Many of the component types included in these reviews are:

- primary containment steel component types such as the containment shell plate, headers and down comers, penetrations, bellows, bracing, supports, restraints, columns and saddles

- building and structural steel component types such as beams, girders, columns, bracing, hangers, plate, and liner plate

- miscellaneous structural steel and aluminum component types such as door frames, blowout panels, tornado vent support frames, plate, sheet metal, penetrations, pipe, tubing, supports, grating, stairs, handrails, storage racks, seismic restraints, and various miscellaneous shapes

- bolts and anchors, such as structural bolts, cast-in-place bolts, and expansion and wedge anchors

The component types are made from carbon steel, low alloy steel, galvanized steel, stainless steel and aluminum. The process for identifying aging effects considers the materials, operating environments and operating stresses. The service environments are discussed in Section C.1.1 of the LRA. In addition, Sections C.1.2.1 through C.1.2.4 of the LRA further discuss steel in various water environments. Applying the process, the applicant identified the following list of aging effects:

- loss of material due to general corrosion, pitting, crevice corrosion, galvanic corrosion, and MIC

- cracking due to fatigue

- Section C.1.4.1 of the LRA discusses these aging effects.

The staff finds the applicant's approach for evaluating the applicable aging effects for structural steel and aluminum components to be reasonable and acceptable. The staff concludes that the applicable aging effects for the component group have been identified.

Concrete Structural Components

The concrete structural components are grouped by the applicant into a commodity to efficiently perform the aging management reviews described in Section C.2.6.1 of the LRA. The following component types that comprise the commodity group:

- masonry block walls
- equipment foundations
- floors, sumps and roofs
- columns, slabs and beams
- interior and exterior walls (above and below grade)

The component types are composed of concrete, reinforcing steel and grout. The process considers the materials, operating environments, and operating stresses. The service environments are discussed in Section C.1.1 of the LRA. Applying the process, the applicant identified the following aging effects:

- loss of material due to corrosion of embedded steel
- cracking in masonry block walls due to expansion or contraction

Section C.1.4.2 of the LRA discusses the above listed aging effects for concrete structural components.

The staff finds the applicant's approach for evaluating the applicable aging effects for concrete structural components to be reasonable and acceptable. The staff concludes that the applicable aging effects for concrete structural components have been identified.

Structural Sealants

The structural sealants are grouped into a commodity by the applicant to efficiently perform the aging management reviews described in Section C.2.6.7 of the LRA. The following sealant types comprise the commodity group and are collectively reviewed:

- joint and caulking sealant in the joints between the exterior precast panels for the reactor buildings

- main control room environmental control system duct gaskets and flex connectors.

The component types are composed of nonmetallic inorganic elastomers, elastomers, and non-asbestos synthetic fibers. The process for identifying the aging effects was applied to structural sealants. The process considers the materials, operating environments and operating stresses. Section C.1.1 of the LRA discusses the service environments. Applying the process, the applicant identified the following list of aging effects:

- material property changes and cracking due to thermal exposure

- loss of adhesion due to exposure to excessive moisture

Section C.1.4.3 of the LRA discusses the above listed aging effects for sealants.

The staff finds the applicant's approach for evaluating the applicable aging effects for structural sealants to be reasonable and acceptable. The staff concludes that the applicable aging effects for structural sealants have been identified.

Acrylic

The tornado vent assembly domes are made of acrylic, and are evaluated in Section C.2.6.8 of the LRA. The acrylic is Plexiglas G cell cast acrylic polymer. The chemical name is polymethyl methacrylate and it is composed of carbon, hydrogen, and oxygen. No fillers are added as part of the forming process and the material contains no significant halogens or sulfur. The process for identifying the aging effects was applied to the acrylic. The process considers the materials and operating environments. The service environments are discussed in Section C.1.1 of the LRA. The applicant identified cracking as the applicable aging effect.

Section C.1.4.4 of the LRA discusses the aging effect.

The staff finds the applicant's approach for evaluating the applicable aging effects for the acrylic tornado vent assembly dome to be reasonable and acceptable. The staff concludes that the applicable aging effects for the tornado vent acrylic dome have been identified.

STRUCTURE AND STRUCTURAL COMPONENT AGING EFFECTS

In order to further facilitate the identification of aging effects requiring management, the applicant evaluated structural components for each structure. A discussion of the aging effects requiring management for each of these structures and structural components follows.

Conduits, Raceways, and Trays

The conduits, raceways, and trays are fabricated from carbon steel, galvanized steel, or aluminum, exposed to an inside or containment atmosphere environment. The applicant identified loss of material as the aging effect for carbon steel, and possibly galvanized steel. Loss of material due to general corrosion, crevice corrosion, pitting corrosion and MIC is considered. It was not clear if galvanized steel is included for loss of material. In its response to RAI 3.6-8, dated October 10, 2000, the applicant stated that galvanized steel exposed to a containment environment is subjected to an inert nitrogen environment during plant operations. The inerted containment environment reduces the potential for corrosion of galvanized steel products. During outage periods, the environment is conditioned indoor air.

The applicant further stated that Section C.1.4.1 of the LRA discusses loss of material as an aging effect for galvanized steel. For galvanized steel exposed to indoor air, loss of material may occur only in areas where crevices may collect moisture. Therefore, galvanized steel exposed to an inside containment environment can experience loss of material due to crevice corrosion, and crevice corrosion is an aging effect requiring management. The staff finds that the applicant's response is consistent with industry experience and, therefore, is acceptable. This response closes staff RAI 3.6-8. The applicant did not identify any aging effects for aluminum exposed to an inside containment environment. The staff agrees that there are no credible aging effects for aluminum exposed to an inside containment environment.

The applicant also did not consider self-loosening of bolted connections by vibration as an aging effect. The staff understands that proper design and installation practices should minimize the likelihood of bolt self-loosening by vibration. However, expansion and undercut anchors in concrete can become loose due to local degradation of surrounding concrete, as a result of vibratory loads. This concern is addressed and resolved in Section 3.6.3.2 of this SER as part of the closure of RAI 3.6-9 (see Conduits, Raceways, and Trays in Section 3.6.3.2 of this SER).

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups for conduits, raceways, and trays.

<u>Control Building</u>

The control building contains various components (e.g., anchors and bolts, blowout panels, miscellaneous steel, reinforced concrete, and structural steel) fabricated from carbon steel, galvanized steel, aluminum, and reinforced concrete exposed to the embedded, inside, and outside environments. The applicant stated that the aging effect for all of these material and environment combinations is loss of material. The reinforced concrete may also be subject to cracking. The staff agrees with the applicant's position.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity component groups in the control building.

<u>Drywell Penetrations</u>

The drywell penetrations are fabricated from carbon steel that is exposed to the containment atmosphere environment and an embedded environment. The applicant identified loss of material as the aging effect in Table 3.3.1-6 of the LRA. The applicant evaluated the aging effect for this material and environment in Section C.2.6.2 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, pitting, and MIC).

As stated before, the applicant has considered loss of material for all containment penetrations and vent line bellows in Tables 3.3.1-3 and 3.3.1-6 of the LRA. In Section C.2.6.2 of the LRA, the applicant states two aging effects; (1) loss of material due to various types of corrosion, and (2) cracking due to fatigue in the localized areas.

In response to RAI 3.6-36 related to the AMR for penetrations in the torus, the applicant points out that the penetrations are covered under primary containment penetrations in Section C.2.6.2 of the LRA, together with the AMR for drywell penetrations. Many torus penetrations are submerged in torus water, an environment distinctly different from that of the penetrations in the drywell, and they require different ISI, coating, and leak-testing procedures. In a letter dated January 5, 2001, the staff asked the applicant to provide justification why the torus penetrations should not be placed in a commodity group other than that for other components in the primary containment (i.e. drywell). By letter date January 31, 2001, the applicant provided a drawing showing a section through the torus and associated penetrations. The drawing also identified the AMPs associated with the penetrations above and below the water line. For torus penetrations above the water line, the applicant takes credit for implementing the inservice inspection program, the primary containment leakage testing program, the protective coating program, and the component cyclic or transient limit program. Additionally, for torus penetrations below the water line and in the splash zone of the torus shell, the applicant takes credit for implementing the suppression pool chemistry control program, the torus submerged component inspection program, and the protective coatings program. Moreover, the applicant states, "a review of torus inspection reports indicates that degradation of the torus coating, in the form of thinned coatings, and some pitting corrosion in the torus immersion area is general in nature and occurs primarily on the torus shell. No specific corrosion has been noted around penetrations welded to the shell. Corrosion is generally more evident near the torus waterline and at or near the bottom of the torus where sludge or small debris collects." The applicant also provides a listing of penetrations in the torus of each unit. This information adequately responds to the staff's concern regarding the AMPs for torus penetrations, and closes RAI 3.6-36. This explanation also provides an acceptable response to the staff's RAI 3.6-41 related to the separate AMP for torus corrosion, RAI 3.6-41 is also closed.

In response to RAI 3.6-37 related to the specific environment around drywell and torus penetrations, the applicant referred to the programs enumerated in Section C.2 of the LRA as noted in Tables 3.3.1-3 and 3.3.1-6 of the LRA. The staff specifically needs information for the environment (i.e., temperature, humidity, cumulative radiation, demineralized water) around groups of primary containment penetrations having similar operating histories in order to ascertain whether the AMPs are appropriate for the specific operating history/environment for individual groups of containment penetrations. By letter dated January 31, 2001, the applicant responded that two types of penetrations are considered: electrical and mechanical (piping). Each drywell electrical penetration is composed of the electrical feed-through assembly and the structural piping to which it is attached. Electrical penetrations are included in the EQ program and the electrical, non-metallic assemblies are evaluated and given a qualified life. The structural part of the penetration is managed by the ISI program. The environmental information below can be considered applicable to all drywell penetrations. The worst-case normal inside-containment environment for all drywell penetrations is as follows:

Temperature: 150°F
Radiation: 9.17 E7 Rads (gamma); 4.5 E16 NVT neutron fluence
Humidity: 50 percent - 90 percent
Moisture/wetting: None

The environment for torus penetrations varies between the submerged and non-submerged penetrations. The worst-case environment for torus penetrations is as follows:

Temperature: 105°F
Radiation: 1.4 E7 rads gamma
Humidity: 50 percent - 90 percent
Moisture/wetting: See visual aid (drawing as discussed above) for submerged penetrations

This information justifies the applicant's focus on the exposure of drywell penetrations to varying environments though they are grouped into the same commodity group. The staff considers RAI 3.6-37 closed.

In response to RAI 3.6-38 related to bellows in the penetrations (other than those in the vent pipes), the applicant referred to the response given to RAI 3.6-37. The staff was basically looking for the operating history of the bellows knowing that the two ply bellows, normally used in containments, undergo gradual degradations and leakage. However, in response to RAI 3.6-42, the applicant provided the following information. The applicant indicated that, upon the receipt of IN 92-20, "Inadequate Local Leak Rate Testing," it decided to select a sample of three bellows for augmented testing to evaluate the adequacy of local leak rate testing (LLRT) methods and procedures. A plate was welded inside containment to test the bellows in the proper direction. The tests confirmed that the testing methods and procedures were acceptable. Some of the two-ply bellows in Unit 2 were replaced because of bellow leakage detected during the LLRT. The bellows leakage was caused by the inadvertent exposure of the bellows to chloride during maintenance activities. This description confirms that the applicant has adequately considered the potential aging effects for monitoring leakage in primary containment bellows. RAIs 3.6-38 and 3.6-42 are considered closed.

On the basis of the above information, the staff finds that the applicant has identified all applicable aging effects for the commodity groups associated with the drywell penetrations.

EDG Building

The EDG building contains various components (e.g., anchors and bolts, miscellaneous steel, reinforced concrete, and structural steel) fabricated from carbon steel, galvanized steel, and concrete exposed to the embedded, inside, and outside environments. The aging effect for all of these material and environment combinations is loss of material.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups in the EDG building.

Fuel Storage

The fuel storage system contains components fabricated from carbon steel, stainless steel, aluminum, and concrete exposed to an inside environment. The applicant identified loss of material as the aging effect for all components made of these materials, except for the aluminum storage racks, exposed to an inside environment. The applicant stated that an inside environment is a "sheltered" environment, which assumes 50 percent to 90 percent humidity, an ambient temperature less than 120°F and a maximum radiation level of 9.0×10^6 rads. The applicable aging effect due to exposure to an inside environment is loss of material due to general corrosion, crevice corrosion, pitting, and MIC of carbon steel and submerged stainless steel components, and due to corrosion of embedded steel for the reinforced concrete.

For components fabricated from stainless steel or aluminum in a demineralized water environment, the applicant identified loss of material as the aging effect in Table 3.3.1-4 of the LRA. The demineralized water is processed on site and is stored in demineralized water storage tanks and condensate storage tanks where impurities and conductivity are maintained at low levels but dissolved oxygen concentrations are neither controlled nor monitored. The applicant stated that the applicable aging effect due to exposure to a demineralized water environment is loss of material due to crevice corrosion, pitting and MIC for stainless steel and galvanic corrosion for aluminum.

According to Table 3.3.1-4, loss of material is an applicable aging effect for stainless steel components in an embedded environment. The fuel pool chemistry control program is the AMP credited with managing this aging effect

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups associated with fuel storage.

Intake Structure

The intake structure contains various components (e.g., anchors and bolts, miscellaneous steel, reinforced concrete, and structural steel) fabricated from carbon steel, galvanized steel, and concrete exposed to embedded, inside, outside, high humidity, submerged, buried, and wetting-other-than-humidity environments. The aging effects for all of these materials and environment combinations is loss of material.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups in the intake structure.

Main Stack

The main stack contains various components (e.g., anchors and bolts, miscellaneous steel, reinforced concrete, and structural steel) fabricated from carbon steel, galvanized steel, copper alloy, and concrete exposed to the inside, embedded, and outside environments. The aging effect for all of these materials and environment combinations is loss of material and cracking.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups in the main stack.

Piping Specialties

For the piping specialties, the applicant stated that hangers and supports for ASME Class I piping (made of carbon steel and galvanized steel) are exposed to a containment atmosphere or inside (sheltered) environment. As discussed in Sections C.1.2.8, C.1.2.9, and C.2.6.4 of the LRA, loss of material is identified as an applicable aging effect. The applicant also stated that hangers and supports for non-ASME Class I piping, tubing, and ducts (made of carbon, galvanized, and stainless steels) are exposed to a containment atmosphere, inside (sheltered), outside, or submerged environment. As discussed in Sections C.1.2.2, C.1.2.8, C1.2.9, and C.2.6.4 of the LRA, loss of material is identified as an applicable aging effect.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups associated with piping specialties.

Primary Containment

The applicant stated that the primary containment system contains various components (e.g., bolts and anchors, containment penetrations, miscellaneous steel) fabricated from carbon steel, galvanized steel, and stainless steel exposed to the containment atmosphere, inside, torus water, embedded, and high humidity environments. The applicant identified loss of material as the aging effect. The applicant evaluated the aging effects for these materials and environment in Sections C.2.6.2 and C.2.2.3.1 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, pitting, and MIC).

The applicant identified loss of material and cracking as the aging effects. According to Table 3.3.1-3 of the LRA, the primary containment system contains various components (e.g., bolts and anchors, blind flange, containment isolation valves, miscellaneous steel) fabricated from carbon steel, possibly galvanized steel, and stainless steel exposed to torus water. The applicant evaluated the aging effects for these materials and environment in Sections C.2.6.1 and C.2.6.2 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, galvanic corrosion, pitting, MIC, and erosion corrosion). RAI 3.6-14 requested the applicant to clarify whether any primary containment galvanized steel components are subject to the torus water environment and, as applicable, indicate the appropriate AMP. The applicant indicated that some galvanized carbon steel grating components that are part of the platforms inside the torus may be intermittently exposed to torus water at some time during operation if the torus water level rises high enough, or if sloshing of the water surface occurs during a safety relief valve (SRV) discharge. The applicant stated that galvanized carbon steel exposed to water may experience a loss of material due to corrosion, and corrosion of galvanized steel components inside the torus is managed by the protective coatings program and by suppression pool chemistry control, as discussed in LRA Section C.2.6.2. This response is sufficient in detail and acceptable. RAI 3.6-14 is considered resolved.

The primary containment system also contains various components (e.g., containment isolation valves, and associated piping) fabricated from carbon steel and stainless steel exposed to demineralized water. The applicant identified loss of material and cracking as the aging effects. The applicant evaluated the aging effects for these materials and environment in Sections C.2.2.2.2 and C.2.2.3.1 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, galvanic corrosion, erosion-corrosion, pitting, and MIC). The applicant also identified cracking as an aging effect caused by thermal fatigue.

The primary containment system contains containment isolation valves and piping fabricated from carbon steel exposed to raw water. The applicant identified loss of material and cracking as the aging effects. The applicant evaluated the aging effects for this material and environment in Section C.2.6.2 of the LRA and identified several forms of corrosion that may result in loss of material.

The primary containment system contains various components (e.g., anchors and bolts, containment penetrations, miscellaneous steel) fabricated from carbon steel and possibly galvanized steel and stainless steel that is embedded. RAI 3.6-18 requested the applicant to clearly indicate the materials that are embedded. The applicant, after its review of screening records and supporting information, identified that only carbon steel components that are listed in Table 3.3.1-3 as embedded are the ones that are embedded items. RAI 3.6-18 is closed.

Staff RAI 3.6-19 requested the applicant to clarify a potential discrepancy between Table 3.3.1-3 and Section C.2.6.2 of the LRA. The applicant stated that cracking identified as a detrimental aging effect in Section C.2.6.2 applies only to cracking due to fatigue of the torus. The applicant further asserted that anchors and bolts, and miscellaneous steel are not subjected to significant vibratory or cyclic loads, and are therefore not subject to cracking. Also, stainless steel bellows, used in some penetrations that are subject to thermal movement or longitudinal operational piping loadings, are designed to withstand the thermal and cyclic loadings to which they are subjected, and are not considered susceptible to cracking. This response resolves RAI 3.6-19. The applicant evaluated the aging effects for these materials and environment in Section C.2.6.2 and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, pitting, and MIC).

The primary containment system contains containment isolation valves, tubing, and piping fabricated from carbon steel and stainless steel exposed to wetted gas. The applicant identified loss of material and cracking as the aging effects. The applicant evaluated the aging effects for this material and environment in Sections C.2.2.9.1 and C.2.2.9.2 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, pitting, crevice corrosion, galvanic corrosion, and MIC). Sections C.2.2.9.1 and C.2.2.9.2 also identified cracking caused by thermal fatigue as an aging effect for these components and this environment.

In Table 3.3.1-3, the applicant identified fatigue cracking for blind flanges (commodity group C.2.2.3.1), containment isolation valves (commodity groups C.2.2.2.2 and C.2.2.3.1, C.2.6.2, C.2.2.9.1, and C.2.2.9.2), piping (commodity groups C.2.2.2.2, C.2.2.3.1, C.2.6.2, C.2.2.9.1, C.2.2.9.2), tubing (commodity group C.2.2.9.2) and vent pipes, vent headers and downcomers (commodity group C.2.6.2). In Section 4 of the LRA, the applicant included thermal fatigue as a TLAA (the staff's evaluation of this TLAA is discussed in Section 4.2 of this SER).

Based on the staff's experience, degradation of piping systems (e.g., loss of integrity of bolted closures, cracking of welds and loosening bolts) may potentially be caused by vibration (mechanical or hydrodynamic) loading. In Table 3.3.1-3 of the LRA, the applicant did not identify loss of preload as an aging effect for bolting in the primary containment system. The applicant was requested via RAI 3.6-50 to clarify whether the vibration related aging effects including cracking of piping welds and loosening of bolts were considered in the aging review for the primary containment system, and if they were excluded, provide the basis. The applicant responded to this RAI in its letter dated October 10, 2000. The applicant stated that the loss of preload in bolted connections of primary containment piping was inadvertently omitted from Table 3.3.1-3. The applicant further stated that it has revised the table to include the aging effect of loss of preload by an electronic communication dated June 20, 2000. The staff finds the applicant's response acceptable and RAI 3.6-50 is closed.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups in the primary containment.

<u>Reactor Building</u>

The reactor building contains various components (e.g., anchors and bolts, blowout panels, panel joint seals and sealants, miscellaneous steel, reinforced concrete, and structural steel) fabricated from either carbon steel, galvanized steel, aluminum, stainless steel, elastomers, concrete, and masonry block exposed to an inside, submerged, and outside environment. The applicant evaluated the aging effects for these materials and environments in Sections C.2.6.1, C.2.6.3, C.2.6.6, and C.2.6.7 of the LRA and identified several aging effects. These include loss of material, loss of adhesion, material property changes and cracking of elastomers, and cracking of concrete and masonry block.

For the reactor building, the applicant stated that carbon steel anchors and bolts are exposed to inside (sheltered) and outside environments. As is discussed in Sections C.1.2.8, C.1.2.9 and C.2.6.3 of the LRA, loss of material is identified by the applicant as an applicable aging effect. The applicant stated that carbon and galvanized miscellaneous steels, as well as structural steels made of carbon, galvanized, and stainless steel are exposed to inside (sheltered), outside and submerged environments. As discussed in Sections C.1.2.2, C.1.2.8, C.1.2.9 and C.2.6.3 of the LRA, loss of material is an applicable aging effect for these structural components. The applicant stated that panel joint seals and sealants made of elastomers (nonmetallic and inorganic) are exposed to inside (sheltered) and outside environments. As discussed in Sections C.1.2.8, C.1.2.9, and C.2.6.7 of the LRA, material property changes, cracking, and loss of adhesion are listed by the applicant as applicable aging effects. The applicant also stated that reinforced concrete structures and components serving functions including structural support, fire barrier, flood barrier, fission product/missile barriers, component shelter/protection, radiation shielding and non-safety-related structural support are made of concrete or masonry blocks and carbon steel reinforcement. These structures and components are exposed to an inside (sheltered) and an outside environment. As discussed in Sections C.1.2.8, C.1.2.9, and C.2.6.1 of the LRA, loss of material and cracking are applicable aging effects for these structural components.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups in the reactor building.

Reactor Building Penetrations

The applicant indicated that the reactor building penetrations are fabricated from carbon steel and galvanized steel that is exposed to the inside and outside environment and an embedded environment. The applicant identified loss of material as the aging effect in Table 3.3.1-7 of the LRA. The applicant evaluated the aging effects for these materials and environment in Section C.2.6.3 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, pitting and MIC).

Table 3.3.1-7 indicates that the aging effects of reactor building (RB) penetrations are managed by the structural monitoring program (SMP) and the protective coating program. However, Section A.2.5 of the LRA does not specifically list reactor building penetrations as part of the SMP. In RAI 3.6-39, the staff requested the applicant to clarify if the RB penetrations are covered under the SMP, or provide information as to where the aging effects of reactor building penetrations are covered. In response to this request, the applicant stated that reactor building penetrations are included in the SMP. The applicant further indicated that Section C.2.6.3 of the LRA, which discusses steel as a commodity group, also explicitly identifies T-54 reactor building penetrations as included in the commodity and SMP is listed among the AMPs applicable to the reactor building penetrations. The applicant's response resolves the staff concern and the issue is closed.

In response to RAI 3.6-39 related to the aging effects for reactor building penetration seals and gaskets and their inclusion of leak-tightness characteristics, the applicant stated that the secondary containment (including reactor building penetrations) is not designed to be leak-tight. Rather, it has controlled leakage characteristics, and is maintained at a negative pressure relative to the outside, so that the air flow is into the building. These characteristics are confirmed periodically by secondary containment leakage tests. The applicant further stated that, in order to manage aging of the reactor building penetrations, aging effects associated with the penetrations are managed prior to such a gross determination of degradation. The relevant AMRs have identified these "first line" aging effects requiring management in the renewal term. Reactor building penetrations are discussed in LRA Tables 3.2.4-18, 3.3.1-7 (described as structural steel), and 3.4.1-1 (as Nelson frames). AMRs are presented in LRA Sections C.2.3.4.1 (for fire penetration seals), C.2.6.3 (for reactor building penetrations structural steel), and C.2.5.2 (for Nelson frames). The AMR for the neoprene rubber inserts in Nelson Frames determined that there were no aging effects requiring management.

The response to RAI 3.6-39 indicates that to serve as a fission product barrier, the reactor building penetrations should have an AMP related to the reactor building penetrations' leak-tightness. A review of the Plant Hatch Technical Specifications (TS Section B 3.6.4.1) indicates that the limiting condition for operation, its applicability, and action and surveillance requirements for secondary containment provide adequate assurance that the leak-tightness characteristics of these penetrations will be monitored and maintained periodically during the period of extended operation. By letter dated January 5, 2001, the staff asked the applicant to provide justification as to why the TS requirements should not be included as part of the total aging management program for reactor building penetrations.

By letter dated January 31, 2001, the applicant stated that numerous penetrations are considered to be secondary containment penetrations. The principal types of penetrations are mechanical (for piping), electrical (for conduits and cable trays) and HVAC (for HVAC ducts). Mechanical penetrations are of all-welded construction, and have no seals or gaskets (see LRA Table 3.3.1-7). Also, there are no seals and gaskets in HVAC ducts credited for maintaining secondary containment. Fire penetration seals located in fire barrier penetrations are managed by fire protection activities as shown in LRA Table 3.2.4-18. The penetrations for electrical conduits and cable trays consist of Nelson frames. There are no aging effects for the polymers and the steel of the Nelson Frames per LRA Table 3.4.1-1.

Moreover, the applicant states that any contribution of reactor building penetrations to secondary containment in-leakage is thus, extremely small. In addition, even if a mechanism were postulated that would result in degradation of penetrations leading to secondary containment in-leakage, the Plant Hatch Technical Specification Surveillance Requirements for secondary containment do not provide a useful tool for license renewal due to the relative magnitude of postulated reactor building penetration in-leakage as compared with other, dominant pathways.

Additionally, the applicant states that other secondary containment in-leakage pathways include reactor building doors and caulked joints associated with the reactor building walls. Reactor building doors are not part of the reactor building penetrations.

By letter dated January 31, 2001, the applicant referenced a telephone conference on January 26, 2001, in which the overall drawdown characteristics of the reactor building were discussed. The applicant pointed out that outside and apart from license renewal, as part of the numerous performance-based tests that are routinely performed by Plant Hatch as part of the Technical Specifications, a periodic test is performed which identifies the drawdown characteristics of the secondary containment. However, for license renewal, the applicant observes that aging degradation of each in-leakage pathway contributor is managed by programs credited in the LRA to maintain intended function. The various applicable sections of the LRA are noted in the above paragraphs.

The response above did not address the staff's concern about managing the controlled leakage characteristics of the secondary containment system (including its penetrations). In Section 2.4.7 of the LRA, the intended function of the reactor building penetrations (T54-01) is "maintain secondary containment leakage rates within design limits." In TS Section B 3.6.4.1, under "LCO," it is stated "For the secondary containment to be OPERABLE, it must have adequate leak tightness to ensure that the required (0.2 inch) vacuum can be established and maintained." Numerous penetrations associated with the reactor building could contribute towards violating the design limits established for secondary containment (i.e., reactor building). Thus, the applicant should have an

AMP to demonstrate that the overall effect of numerous degradations has not violated the leakage characteristics of the reactor building. This was identified as Open Item 3.6.3.1-1.

By letter dated June 5, 2001, the applicant responded to this open item. The applicant stated that it had revised the structural monitoring program to include the provisions of Surveillance Requirement 3.6.4.1.4 of the Unit 1 and 2 technical specifications. The draw-down test performed pursuant to the surveillance requirement will be credited for aging management as an additional detection measure that is capable of detecting gross changes in flow that may be indicative of age-related degradation. The applicant also revised the FSAR Supplement to reflect this change.

On the basis of the applicant's inclusion of the secondary containment draw-down test as per the surveillance requirements of the TS, as a means to detect gross age-related degradation of secondary containment, the staff concludes that the applicant has an adequate AMP to demonstrate that the overall effect of numerous degradations will not violate the leakage characteristics of the reactor building. Open Item 3.6.3.1-1 is closed.

In response to RAI 3.6-40, related to the benchmarking of the reactor building penetration coating, the applicant stated, "A baseline inspection program will be done for the penetrations prior to the start of the renewal period. The periodicity of future inspections will be determined by a plant coating specialist based on the findings of the initial inspection." The staff finds this response adequate and RAI 3.6-40 is closed.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups associated with the reactor building penetrations.

Turbine Building

The applicant stated that the turbine building has components that are fabricated from carbon steel and galvanized steel (e.g., anchors and bolts, miscellaneous steel, reinforced concrete, and structural steel) that are exposed to the inside, outside, wetting-other-than-humidity, buried, and embedded environments. The applicant identified loss of material as the aging effect in Table 3.3.1-8 of the LRA. The applicant evaluated the aging effects for these materials and environment in Sections C.2.6.1 and C.2.6.3 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, pitting and MIC for steel and corrosion of embedded steel in the concrete). The applicant identified cracking as an aging effect for concrete and masonry block walls in Section C.2.6.1, but did not identify cracking as an aging effect in Table 3.3.1-8. In RAI 3.6-52, the staff requested The applicant to clarify this discrepancy. In its January 31, 2001 response to the request, the applicant stated that there are masonry block walls in the turbine building, but none of these are in close proximity to, or have attachments from, safety related piping or equipment, and hence do not perform an intended function and are not in scope. Additionally, during a December 2000 meeting, the staff requested that the applicant address whether any block walls within the scope of A-46 evaluations are in the turbine buildings. The applicant responded that there were no A-46 block walls in the turbine buildings. The above responses resolve the staff concerns and the issues are judged as closed.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups in the turbine building.

Yard Structures

The yard structures contain various components (e.g., anchors and bolts, cover plates for pull boxes, miscellaneous steel, reinforced concrete, and structural steel) fabricated from carbon steel, galvanized steel, aluminum and concrete exposed to inside and outside environments. The applicant stated that the aging effects for all of these material and environment combinations is loss of material.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups in the yard structures.

3.6.3.2 Aging Management Programs

Once the set of aging effects requiring management was identified for a particular commodity group, a list of aging management programs credited for managing aging of structures or components within the commodity group was produced. This list was compiled by examining the aspects of current programs in plant procedures and program documents. The staff concurs with this approach to identifying applicable aging management programs.

A discussion of the aging management programs credited for managing the aging effects for commodity groups in structures and structural components follows.

Conduits, Raceways, and Trays

To manage corrosion-induced aging effects for carbon steel components and galvanized steel components that show signs of rust, exposed to an inside containment environment in the conduits, raceways, and trays, the applicant relies on the following aging management programs:

- structural monitoring program
- protective coatings program

The SMP provides condition monitoring and appraisal of certain structures, including the conduits, raceways, and trays. The structural monitoring program is discussed in detail in Section 3.1.22 of this SER. The protective coatings program provides a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the associated environment. It is a mitigation and condition monitoring program designed to provide base metal aging management through application, maintenance, and inspection of protective coatings on selected components and structures. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

In Table 3.3.1-2 of the LRA, the applicant identified loss of material due to corrosion of carbon steel and galvanized steel as a plausible aging effect. The applicant also discussed aging effects for the loss of materials in Section C.2.6.4 of the LRA and took credit for the SMP and the protective coatings program as applicable AMPs. However, the applicant did not identify self-loosening of bolted connections due to vibration as an aging effect. The staff believes that expansion and undercut anchors in concrete may become loose due to local degradation of the surrounding concrete as a result of vibratory loads. RAI 3.6-9 requested the applicant to provide the technical justification for not identifying loss of preload due to the effects of vibration on concrete surrounding expansion and undercut anchors.

In its letter dated October 10, 2000, the applicant stated that structural supports, including hangers and cable trays, are passive structural components that are rarely subjected to high displacement vibration loading, or high stress vibration loading. Cable trays are isolated from rotating equipment or active equipment by the use of flexible conduits or cables. No gaskets are used in structural connections. For structural joints installed with proper torque, the initial loss of preload is limited, and sufficient preload remains to assure joint integrity. The applicant further stated that structural bolts and anchors at Plant Hatch were installed and inspected per vendor recommendations and in accordance with plant procedures. Per Electric Power Research Institute (EPRI) Bolting Procedures Reference Manual, NP5067, Vol. 1, "A Reference Manual for Nuclear Power Plant Maintenance Personnel, Large Bolt Manual," loss of preload over an extended period requires elevated temperatures, stress levels in proximity to the material yield stress, and cyclic loading. Structural supports, hangers, bolts and anchors are not subject to high temperatures, high displacement vibration loading, or high stress vibration loading. The applicant also indicated that a review of the plant operating history for the last 5 years did not identify any deficiencies resulting from loss of anchor or bolt preload and loss of preload in structural joints has not been identified as a widespread industry problem. Therefore, the Plant Hatch aging management review concluded that loss of preload due to vibratory loads is not an aging effect requiring management for bolts or anchors used by structural supports, hangers or cable trays.

Additionally, the applicant stated that Class 1 seismic structures at Plant Hatch are designed in accordance with American Concrete Institute (ACI) 318-63, "Building Code Requirements for Reinforced Concrete." EPRI Report TR-103842, "Class 1 Structures Industry Report," Revision 1, dated July 1994, evaluated the effect of cyclic loads on concrete structures. The report concluded that cycle loading (fatigue) would not cause significant degradation of concrete structures designed in accordance with ACI 318. The design stress level is limited to less than 50 percent of the static strength, and the structures can resist extremely high cycles of loading in the low amplitude, low stress range, and actual stresses from any high cycle loading on concrete structures, such as those from machine vibration, are a small portion of the combined stresses resulting from static and dynamic loads. A review of the plant operating history for the last 5 years did not identify any deficiencies resulting from loss of anchor bolt, expansion bolt, or undercut anchor preload. Therefore, the aging management review concluded that local degradation of the concrete surrounding anchors, because of vibratory loads, is not an aging effect requiring management, and would not cause loss of preload for support anchors.

The staff reviewed the above justification provided by the applicant, including Plant Hatch's past 5 years of operating experience, and concurs with the above findings. RAI 3.6-9 is closed.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups associated with conduits, raceways, and trays will be adequately managed by the above listed AMPs.

Control Building

To manage corrosion-induced effects of aging for components fabricated from carbon steel, galvanized steel, aluminum, and concrete exposed to inside, embedded, and outside environments in the control building, the applicant relies on the following aging management programs:

- protective coatings program
- structural monitoring program

Because some of these components may be susceptible to loss of material, the protective coatings program provides for periodic inspection of component external surfaces. This program will also provide for proper corrective actions (such as replacement or coating of exposed surfaces) to prevent significant degradation of these components due to loss of material. The structural monitoring program provides condition monitoring and appraisal of certain structures, including the control building. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the control building will be adequately managed by the above listed AMPs.

Drywell Penetrations

Aging management programs determined by the applicant to manage aging effects requiring management for drywell penetrations are:

- protective coatings program
- inservice inspection program (ISI Program)
- primary containment leakage rate testing program

The protective coatings program provides for periodic inspection of structural component surfaces, including fasteners and associated coatings. This program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion.

The ISI Program provides for visual inspections of internal and external surfaces and fasteners, thereby providing assurance that the containment shell and internal structures have not degraded due to corrosion and/or cracking. Inspections are conducted in accordance with ASME Section XI Table IWE-2500-1.

Primary containment leak rate testing procedures provide for the scheduled periodic testing of the primary containment pressure boundary and pressure boundary penetrations to detect degradation of the pressure boundary. Inspections are conducted in accordance with 10 CFR Part 50, Appendix J.

The staff's detailed review of these programs may be found in Sections 3.1.9, 3.1.14, and 3.1.20 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups associated with the drywell penetrations will be adequately managed by the above listed AMPs.

EDG Building

To manage corrosion induced effects of aging for components fabricated from carbon steel, galvanized steel, and concrete exposed to inside and outside environments in the EDG building, the applicant identified the following aging management programs:

- protective coatings program
- structural monitoring program

Because some of these components may be susceptible to loss of material, the protective coatings program provides for periodic inspection of component external surfaces. This program will also provide for proper corrective actions (such as replacement or coating of exposed surfaces) to prevent significant degradation of these components due to loss of material. The structural monitoring program provides condition monitoring and appraisal of certain structures, including the EDG Building. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the EDG building will be adequately managed by the above listed AMPs.

Fuel Storage

To manage corrosion-induced aging effects for carbon steel, stainless steel, and concrete components exposed to an inside environment in the fuel storage areas the applicant relies on:

- structural monitoring program
- protective coatings program

The structural monitoring program provides condition monitoring and appraisal of certain structures, including those associated with fuel storage. The protective coatings program provides a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the associated environment. It is a mitigation and condition monitoring program designed to provide base metal aging management through application, maintenance and inspection of protective coatings on selected components and structures. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

To manage the corrosion-induced aging effects for stainless steel and aluminum components exposed to a demineralized water environment, the applicant relies on the fuel pool chemistry control program. This program is intended to mitigate aging in the fuel pool liner and associated components by controlling fluid purity and composition. The related activities are discussed in detail in Section 3.1.5 of the SER.

Table 3.3.1-4 of the LRA identifies loss of material as an aging effect for the aluminum restraints in the spent fuel pool (SFP) demineralized water. The applicant discussed the loss of material due to galvanic corrosion, crevice corrosion, pitting, and MIC in LRA Section C.2.6.6 and took credit for fuel pool chemistry control as an AMP; however, Table 3.3.1-4 and Section C.2.6.6 indicate that the aluminum racks do not require an AMP. RAI 3.6-20 asked the applicant to explain the discrepancy. The applicant stated that the aluminum racks, described as storage racks in LRA Table 3.3.1-4, are located in the new fuel storage vault. These aluminum racks are exposed to air only. There are no aging effects requiring management for aluminum exposed to air. A revised six-column table to re-label the new fuel racks is included in the response to RAI 3.6-24. The staff finds this justification adequate and acceptable. Thus, RAI 3.6-20 is closed.

Section C.2.6.5 of the LRA stated that the applicant regularly checks SFP chemistry control activities under the fuel pool chemistry control program. RAI 3.6-21 requested the applicant to explain how this program manages cracking of stainless steel components (e.g., liner plate). To determine whether these inspections help to ensure that cracking does not occur, the staff needs to know whether these inspections check for cracking, the techniques used, and how many times such inspections of the spent fuel system stainless steel components have been performed to date. Additionally, the staff noted that LRA Table 3.3.1-4 does not list cracking of spent fuel pool stainless steel liners as an aging effect under the structural steel category. Therefore, RAI 3.6-31 asked the applicant to justify its exclusion of this aging effect from Table 3.3.1-4, or provide a plant-specific discussion of the aging effect and the appropriate AMP for managing the cracking of spent fuel pool stainless steel liners. The applicant stated that the water in the pool is demineralized water. Operating temperature data in the spent fuel pools was reviewed by the applicant, and the maximum recorded pool temperature did not exceed 115 °F. This temperature is less than the 140° F threshold established in Section C.1.2.2.2 of the LRA for SCC, regardless of the dissolved oxygen content. Therefore, SCC for the spent fuel pool stainless steel liners and other stainless steel components is not an aging effect requiring management. The staff finds the applicant's justification acceptable and RAIs 3.6-21 and 3.6-31 are closed. The staff reviewed the fuel pool chemistry control program in Section 3.1.5 of this SER.

The fuel storage system contains components fabricated from carbon steel, stainless steel, aluminum, and concrete exposed to an inside environment. Table 3.3.1-4 of the LRA does not clearly identify the environments for which the listed aging effects are managed by the corresponding AMPs. RAI 3.6-23 requested the applicant to clarify the environments for which the listed aging effect occurs and the AMP that manages the aging effect. Furthermore, according to Table 3.3.1-4, loss of material is an applicable aging effect for stainless steel components in an embedded environment. However, based on the information in the same table, there is no applicable AMP or activity identified. RAI 3.6-24 asked the applicant to specify the applicable AMP to manage loss of material for stainless steel components in an embedded environment or provide the basis for concluding that an AMP is not required. In its response, the applicant revised Table 3.3.1-4 to achieve needed clarity. The staff finds the applicant's table revision reasonable and RAIs 3.6-23 and 3.6-24 are considered closed.

Bolts, which are used in safety-related and non-safety-related structural support, are fuel storage system components in the anchors and bolts (C.2.6.5) commodity group, and these bolts are susceptible to a loss of pre-load (due to embedment, gasket creep, thermal effects, and self-loosening). RAIs 3.6-25 and 3.6-28 requested that the applicant provide the basis for not including this aging effect. The applicant resolved this RAI based on justifications provided in its response to staff RAI 3.6-9 included in its letter to the staff dated October 10, 2000 (see discussion under Conduits, Raceways, and Trays, above). RAIs 3.6-25 and 3.6-28 are closed.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups associated with fuel storage will be adequately managed by the above listed AMPs.

Intake Structure

To manage corrosion induced effects of aging for components fabricated from carbon steel, galvanized steel, and concrete exposed to the inside and outside environments in the intake structure, the applicant designated the following aging management programs:

- protective coatings program
- structural monitoring program

Because some of these components may be susceptible to loss of material, the protective coatings program provides for periodic inspection of component external surfaces. This program will also provide for proper corrective actions to prevent significant degradation of these components due to loss of material (such as replacement or coating of exposed surfaces). The structural monitoring program provides condition monitoring and appraisal of certain structures, including the intake structure. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

RAI 3.6-34 asked if Plant Hatch has any earthen embankments as part of its ultimate heat sink system or intake structure and asked the applicant to discuss, as applicable, the aging effects of these structures due to loss of material from erosion and cracking due to settlement. The applicant stated that there is no earthen embankment included as part of the Plant Hatch ultimate heat sink. The river intake structure is located on the south bank of the Altamaha River. It is flanked by a circular steel sheet pile cell on each side near the front of the structure. The main river channel, where the water speeds are greatest, is located closer to the north bank of the river. Erosion has not been a problem on the south bank of the river near the intake structure. Settlement of the intake structure has been monitored since construction. Settlement has been within predicted values, and has leveled off. Therefore, erosion of the soil at the intake structure, and cracking due to settlement or differential settlement are not considered to be aging effects requiring management for the intake structure. This response is sufficient to resolve RAI 3.6-34.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the intake structure will be adequately managed by the above listed AMPs.

<u>Main Stack</u>

To manage corrosion-induced effects of aging for components fabricated from carbon steel, galvanized steel, and concrete exposed to inside and outside environments in the main stack, the applicant relies on the following aging management programs:

- protective coatings program
- structural monitoring program

Because some of these components may be susceptible to loss of material, the protective coatings program provides for periodic inspection of component external surfaces. This program will also provide for proper corrective actions (such as replacement or coating of exposed surfaces) to prevent significant degradation of these components due to loss of material. The structural monitoring program provides condition monitoring and appraisal of certain structures, including the main stack. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the main stack will be adequately managed by the above listed AMPs.

Piping Specialties

To manage aging effects for hangers and supports for ASME Class I piping, and hangers and supports for non-ASME Class I piping, tubing, and ducts, made of carbon, galvanized, and stainless steels, that are exposed to containment atmosphere, inside (sheltered), outside, and submerged environments associated with piping specialties, the applicant identified the following aging management programs for managing the aging effects:

- protective coatings program
- structural monitoring program

The applicant cited the above programs to manage loss of material for the structural components exposed to the described environments. The staff has verified that these two programs are included in Section C.2.6.4 of the LRA as applicable aging management programs. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups associated with piping specialties will be adequately managed by the above listed AMPs.

Primary Containment

AMPs determined by the applicant to manage aging effects requiring management in the primary containment are:

- protective coatings program
- ISI program
- suppression pool chemistry control
- primary containment leak rate testing program
- demineralized water and condensate storage tank chemistry control
- treated water systems piping inspections
- gas systems component inspections
- passive component inspection activities
- structural monitoring program
- component cyclic or transient limit program

The protective coatings program provides for periodic inspection of structural component surfaces, including fasteners and associated service level I coatings (service level I coatings are used in areas inside the reactor containment where coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown). This program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion.

The ISI Program provides for visual inspection of internal and external surfaces and fasteners, thereby providing assurance that the containment shell and internal structures have not degraded due to corrosion and/or cracking. Inspections are conducted in accordance with ASME Section XI Table IWE-2500-1.

Suppression pool chemistry control limits detrimental impurities and conductivity within the suppression pool and thereby mitigates aging. Suppression pool chemistry control implements the EPRI guidance on BWR water chemistry for auxiliary systems.

Primary containment leak rate testing procedures provide for the scheduled periodic testing of the primary containment pressure boundary and pressure boundary penetrations to detect degradation of the pressure boundary. Inspections and testing are conducted in accordance with 10 CFR Part 50, Appendix J.

Demineralized water and condensate storage tank chemistry control serve to mitigate loss of material due to pitting, crevice corrosion, or MIC by limiting concentrations of detrimental impurities and conductivity. Demineralized water quality is monitored on a weekly basis and corrective actions are taken in the event that any limits are exceeded.

Demineralized water and condensate storage tank chemistry control implement EPRI BWR water chemistry guidelines.

The treated water systems piping inspections serve to validate the adequacy of demineralized water and condensate storage tank chemistry control in mitigating loss of material within stainless steels by performing appropriate examinations of a sample population of the susceptible locations.

Aging effects due to corrosion will be detected for these components through gas systems component inspections. This activity will involve appropriate inspections of a representative sample of the most likely degradation locations.

The passive component inspection activities serve to validate the adequacy of the drywell floor and equipment sump discharge piping sections to perform a primary containment function by performing inspections, similar to VT-1, of component internal surfaces any time an applicable component is opened for periodic maintenance or repair. This information is evaluated and trended to provide adequate assurance that any significant aging trends are identified and corrected.

The SMP inspection process assesses the ongoing overall conditions of structures and identifies any ongoing degradation. The SMP will inspect the concrete commodities for loss of material, cracking, and spalling. The SMP will also visually inspect masonry block walls for cracking.

Management of cracking due to fatigue of the torus is implemented via a component cyclic or transient limit program. The component cyclic or transient limit program is designed to track cyclic and transient occurrences, including the limiting location for the torus, to ensure that reactor coolant pressure boundary components will remain within the ASME Code Section III limits.

The staff's detailed review of these programs may be found in Sections 3.1.6, 3.1.7, 3.1.9, 3.1.12, 3.1.14, 3.1.20, 3.1.22, 3.1.24, 3.1.25, and 3.1.27 of this SER.

In response to RAI 3.6-41 related to torus corrosion, the applicant provided a description of torus degradation found in both Plant Hatch units. However, the applicant emphasized that, in spite of the degradation, the actual shell thicknesses are well above the required minimum shell thicknesses. The applicant stated that it plans to continue to perform desludging, visual examination, and spot coating repairs periodically, based on the history of past inspection. The staff believed that operating experience at Plant Hatch and other industry operating experience related to torus corrosion indicated a need for a program to manage torus corrosion during the period of extended operation. In Open Item 3.6.3.2-1(a), the staff requested the applicant to provide justification as to why this program should not be a separate program in the LRA.

By letter dated January 31, 2001, the applicant provided a drawing showing a section through the torus and associated penetrations. The drawing also identified the AMPs associated with the penetrations above and below the water line. For torus penetrations above the water line, the applicant takes credit for implementing the inservice inspection program, the primary containment leakage testing program, the protective coating program, and the component cyclic or transient limit program. Additionally, for torus penetrations below the water line and in the splash zone of the torus shell, the applicant takes credit for implementing the suppression pool chemistry control program, the torus submerged component inspection program, and the protective coatings program. Moreover, the applicant states, "a review of torus inspection reports indicates that degradation of the torus coating, in the form of thinned coatings, and some pitting corrosion in the torus immersion area is general in nature and occurs primarily on the torus shell. No specific corrosion has been noted around penetrations welded to the shell. Corrosion is generally more evident near the torus waterline and at or near the bottom of the torus where sludge or small debris collects." The applicant also provides a listing of penetrations in the torus of each unit. This information adequately responds to the staff's concern regarding the AMPs for torus degradation, and closes Open Item 3.6.3.2-1(a).

Section C.2.6.2 of the LRA stated that the ISI program provides for visual inspection of the internal and external surfaces and fasteners, thereby providing assurance that the containment shell and internal structures have not degraded due to corrosion and/or cracking. 10 CFR 50.55a endorsed the ASME Section XI, Subsection IWE Code with the condition that 10 CFR 50.55a(b)(2)(ix) provisions be complied with. The LRA is not clear regarding this requirement. RAI 3.6-11 asked the applicant to confirm that both the scope and the detail of the inspection implemented in accordance with ASME Section XI Table IWE-2500-1 also comply with the requirements for 10 CFR 50.55a(b)(2)(ix). The RAI also asked the applicant to discuss how it is implementing a staff position that applicants for license renewal need to evaluate, on a case-by-case basis, the acceptability of inaccessible areas even though conditions in accessible areas may not indicate the presence of degradation in inaccessible areas. The applicant stated that it complies with the inspection requirements of 10CFR50.55a(b)(2)(ix) with one exception. Details of this exception, which is identified as Plant Hatch's relief request MC-9, are contained in the applicant's submittal to the NRC dated July 19, 2000. By letter dated October 4, 2000, the staff concluded that the proposed alternative will provide an acceptable level of quality and safety. The applicant further stated that Section C.2.6.2 of the LRA identifies any applicable aging effects for steel commodities for primary containment and internal structures. Aging effects determined to require management are based on the environment present for the commodity. Each commodity was evaluated for the maximum expected conditions, such as maximum neutron exposure, elevated temperature and high humidity. The applicant maintained that neutron exposure and elevated temperature do not exceed the threshold limits where degradation could occur. Other environmental conditions do not result in different aging effects for inaccessible areas than are applicable to accessible areas. Therefore, for inaccessible areas, no aging effect has been identified that is different from those resulting from the environmental conditions in the accessible areas. On the basis of the review of the above information, the staff concludes that the applicant complies with the requirements for 10 CFR 50.55a(b)(2)(ix).

However, the applicant did not fully answer the second part of the question related to implementation of the staff position regarding how applicants for license renewal will evaluate the acceptability of inaccessible areas even though conditions in accessible areas may not indicate the presence of degradation in inaccessible areas. In a letter dated January 5, 2001, the staff requested the applicant to provide additional information regarding the staff position.

In its response of January 31, 2001, the applicant stated that it's programmatic activities related to the above item are consistent with the draft GALL. In particular, the Plant Hatch inservice inspection program included requirements of the NRC Final Rule 10 CFR 50.55a [including 10 CFR 50.55a(b)(2)(ix)] along with the ASME Section XI Subsection IWE for examination of the Class MC components. The applicant further stated that at Plant Hatch, the designation "inaccessible areas" is limited to two specific areas: (a) Embedded containment shell and (b) containment basemat and buried external walls. Aging is an issue for the containment basemat and buried external walls if ground water or soil aggressive chemical limits per NUREG 1611, "Aging Management of Nuclear Power Plant Containments for License Renewal," are exceeded. The applicant stated that the groundwater and soil parameter at Plant Hatch are within the acceptable limits (pH>5.5, chloride<550 ppm, & sulfate<1500 ppm) specified in NUREG 1611. The soil chemistry at Plant Hatch should be essentially the same as it was before and after the plant was constructed. The soil in the vicinity of the seismic category I structures is compacted backfill with non-aggressive chemical characteristics. The soil in the remainder of the plant site area is generally undisturbed soil. Soil chemistry generally reflects the same chemical composition as the ground water and surface water to which it is exposed. The water chemistry in the Altamaha River is very nearly the same as it was when the plant was constructed. The chemistry of the soil in the vicinity of the plant buildings should also be very nearly the same as it was when the plant was constructed. Thus, the applicant concluded that ground water is not aggressive, and no special aging management program is required. However, the SMP document has been revised to include the following directrive: "Additional emphasis will be placed on the importance of inspecting and documenting the condition of normally inaccessible (underground or embedded) structures, whenever the inaccessible structural components are exposed or uncovered."

The applicant also concluded that aging is not a concern for the embedded containment shell, since plant Hatch's concrete quality in contact with the embedded containment liner meets or exceeds the requirements of ACI 318 and ACI 201.2R; the concrete is subjected to periodic inspection to assure that it is free of penetrating cracks; the moisture barrier is subject to IWE Category E-D Examination; repair or replacement is performed based on inspection results, and boric acid is not used and other chemical spills or water ponding are not common in the containment.

The staff concludes that the above discussion fully addresses the staff position and the issue is closed.

Section A.1.9.4 of the LRA stated that loss of material, cracking, loss of pre-load, and loss of fracture toughness are the aging effects monitored by the Plant Hatch ISI Program. RAI 3.6-12 requested that the applicant provide a discussion of past experience with respect to managing and monitoring these aging effects, including experience with the embedded shell and the sand pocket regions of the primary containment and the loss of pre-load for metal fasteners. The applicant stated that a general discussion of operating experience related to the ISI program is provided in Section B.1.9 of the LRA. The applicant further stated that visual examinations of the mastic seal between the concrete floor at elevation 114'-0" and the drywell shell inside the drywell are performed at every outage. The condition of the seal is carefully inspected to detect any cuts, tears, or observed degradation of the flexible covering over the seal. The mastic seal was replaced on Unit 1 in the fall, 1994 refueling outage. Minor, localized surface pitting was detected but was not significant. The area was cleaned and recoated prior to installation of the new seal. The mastic seal was replaced on Unit 2 in the fall, 1995 refueling outage. There has been no evidence of significant moisture intrusion between the mastic seal and drywell shell or significant deterioration of the shell on either unit. Periodic inspections of the sand cushion and associated air gap drains have confirmed that there was no moisture present or any evidence of prior leakage into the area. The applicant further stated that inspections in the accessible area of the sand cushions have not shown any moisture buildup or corrosion. Visual inspections included associated bolted connections to confirm connection integrity, and no looseness of bolts or nuts has been detected that could be attributed to loss of preload.

The staff finds the response to RAI 3.6-12 adequate and acceptable. RAI 3.6-12 is closed.

Table 3.3.1-3 of the LRA does not list attachment welds to the containment shell elements as an item requiring aging management. Welds between integral attachments to the primary containment are included within the scope of ASME Section XI, Subsection IWE. RAI 3.6-13 asked the applicant to discuss how aging effects of the attachment welds will be managed. The applicant indicated that attachment welds to the primary containment shell elements were considered to be a part of the component welded to the shell or the shell itself. The intended function does include pressure boundary and structural support. These intended functions are addressed in the structural steel component function column in Table 3.3.1-3 of the LRA. Therefore, welds were not singled out as a separate commodity or component and were not listed separately in Table 3.3.1-3. The applicant further indicated that the ISI program, described in Section B.1.9 of the LRA, complies with Subsection IWE of Section XI of the ASME Code and that the ISI program is the aging management program that manages aging of attachment welds to the containment pressure boundary. This is discussed in Section C.2.6.2 and Table C.2.6.2-1 of the LRA. The staff finds this response adequate and acceptable. RAI 3.6-13 is resolved.

Table 3.3.1-3 of the LRA did not provide any information regarding the aging management (including surveillance requirements) for gears, latches, and linkages of personnel hatches and penetrations. RAI 3.6-15 requested that the applicant identify where fretting and lockup of hinges, locks, and closure mechanisms for personnel hatches is discussed in the LRA, or provide a technical justification for not considering fretting and lockup as applicable aging effects for these components. The RAI also asked that the applicant provide a description of the AMP for the personnel hatches, consistent with the 10 elements in the SRP-LR, in sufficient detail to allow the staff to assess the adequacy of this program to manage the applicable aging effects. The applicant responded that locks and closure mechanisms are active components, and are not subject to an AMR. Therefore, fretting and lockup of hinges, locks, and closure mechanisms for personnel hatches and penetrations are not discussed in the LRA. However, aging management for personnel airlocks, hatches, equipment hatches, and penetrations are managed by the ISI program, protective coatings program, and primary leak rate testing program, as discussed in LRA Sections C.2.6.2, A.1.9, A.2.3, and A.1.14. This was identified as Open Item 3.6.3.2-1(b).

The primary containment leakage testing program is described in Section 18.2.14 of the Plant Hatch FSAR Supplement. It states that the applicant has chosen to identify the performance-based requirements and criteria for pre-operational testing and subsequent periodic leakage rate testing. The program ensures that leakage through the primary containment, or through systems and components that penetrate the primary containment, does not exceed allowable leakage rates specified in the TS, and that the integrity of the containment structure is maintained during its service life.

The staff notes that the applicant's approach conforms with the performance-based approach described in Section XI.S4 of the Generic Aging Lessons Learned (GALL) report that was reviewed and approved by the staff, and issued in July, 2001. As such, the staff concludes that aging management by the ISI program, protective coatings program, and primary leak rate testing program, for personnel airlocks, hatches, equipment hatches, and penetrations , is adequate to ensure that leakage through the primary containment, or through systems and components that penetrate the primary containment, does not exceed allowable leakage rates. Open Item 3.6.3.2-1(b) is closed.

Table C.1.1-1 of the LRA shows expected measured temperatures at key plant locations. With respect to the primary containment, the table does not provide maximum temperatures within key containment locations. RAI 3.6-48 asked that the applicant provide maximum recorded or observed temperatures within the primary containment (both normal and abnormal temperatures) at the primary shield wall, reactor vessel supports, main steam line cubicle (or its equivalent) and the hottest regions of the SFP concrete wall locations, and as applicable, discuss the AMP for managing the aging effects of reinforced concrete components subject to a sustained high temperature environment (e.g., concrete temperature greater than 150 °F). The applicant provided the requested information in response to the RAI and summarized that general elevated air temperatures near the concrete structures do not exceed 150 °F on a sustained basis, except for the sacrificial shield wall surrounding the reactor vessel. The applicant also stated that local air temperatures are less than 200 °F, except for the upper elevations of the sacrificial shield wall, and the SMP will inspect the exposed and accessible concrete for loss of material, cracking and spalling. The applicant further indicated that its SMP inspection process should be able to assess the condition of the in-scope structures, and identify any ongoing degradation.

The staff noted that Tables 3.3.1-3 through 3.3.1-5 and 3.3.1-8 through 3.3.1-13 of the LRA do not list cracking of equipment support concrete pads as an applicable aging effect requiring management. Staff experience with other LRAs indicates the frequent occurrence of such cracks around anchor bolt regions. RAI 3.6-49 requested that the applicant discuss the AMP for managing this aging effect or justify its exclusion from the tables listed above. The applicant stated that equipment support foundations, pads, and anchor bolts have been subjected to an AMR. Loss of material due to corrosion of embedded steel was identified as the plausible aging effect, and cracking and spalling were identified as the aging mechanisms (see Sections C.1.4.2 and C.2.6.1 of the LRA). The SMP has been credited as the AMP, and Tables 3.3.1-3 through 3.3.1-5 and 3.3.1-8 through 3.3.1-13 list loss of material as the aging effect requiring management. The applicant's responses to RAIs 3.6-48 and 3.6-49 are adequate to close the RAIs.

The applicant identified several aging management programs to manage cracking for the primary containment system components. A complete discussion on the applicable aging management programs is provided in Section 3.1 of this SER. In Table 3.3.1-3 of the LRA, the applicant included anchors and bolts, structural steel, and miscellaneous steel in non safety-related structural supports. However, it is not clear whether the scope of the primary containment system discussed in Table 3.3.1-3 of the LRA includes any spatially-related components and piping segments within the category of "Seismic II over I" (a non-seismic Category I system, structure, or component whose failure could cause loss of safety function of a seismic Category I system, structure, or component) piping. Through issuance of staff RAI 3.6-51, the applicant was requested to provide clarification.

The applicant was also requested to clarify how the aging management programs for the non-safety-related piping segments and components have been addressed. Specifically, the applicant was requested to state whether the same aging management programs discussed in LRA Table 3.3.1-3 also apply to those "Seismic II over I" piping components.

The applicant responded to this RAI in its letter dated October 10, 2000. The applicant stated that the pipe supports for the seismic II over I piping systems are within the scope of license renewal and they are subjected to the same AMPs as the supports for safety-related piping systems. The applicant also stated that no AMPs are applied to out-of-scope piping segments supported by seismic II over I piping supports. In a telephone conversation on October 24, 2000, the applicant further clarified that within the context of the Plant Hatch CLB, the piping systems are postulated to fall in a seismic event if not seismically supported. Thus, as required for protection of safety-related piping, some non safety-related piping is seismically supported. Those supports are within the scope of license renewal, but the applicant stated that the seismic II over I piping segments are not within the scope of license renewal. The staff finds that the programs to manage aging for the pipe supports are acceptable.

The staff did not agree with the applicant's scoping criteria for seismic II over I piping systems. The staff's position is that the seismic II over I piping segments, whose failure could prevent safety-related systems and structures from accomplishing their intended function should be within the scope of license renewal. Additional discussion of this issue is contained in Section 2.1.3.1 of this SER.

A complete discussion of the applicable aging management programs may be found in Section 3.1 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the primary containment will be adequately managed by the above listed AMPs.

Reactor Building

Aging management programs cited by the applicant to manage aging effects requiring management for the reactor building are:

- protective coatings program
- structural monitoring program

To manage aging effects for carbon steel anchors and bolts exposed to inside (sheltered) and outside environments; and carbon and galvanized miscellaneous steels, and structural steels made of carbon, galvanized and stainless steel, which are exposed to inside (sheltered), outside, and submerged environments, the applicant identified the protective coatings program and the SMP as the applicable aging management programs. The protective coatings program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion. The SMP inspection process assesses the overall conditions of the listed structures, and identifies any degradation. The SMP will inspect the concrete commodities for loss of material, cracking, and spalling. The SMP will also visually inspect masonry block walls for cracking.

To manage aging effects for panel joint seals and sealants made of elastomers (nonmetallic and inorganic), which are exposed to an inside (sheltered) or outside environment, the applicant identified the protective coatings program and the SMP as the applicable aging management programs.

To manage aging effects for concrete, masonry block, and carbon steel, which are exposed to an inside (sheltered) or outside environment, the applicant again identified the protective coatings program and the SMP as the applicable aging management programs.

The staff's detailed review of these programs may be found in Sections 3.1.20, and 3.1.22 of this SER.

The applicant cited the above programs to manage loss of material for the structural components exposed to the described environments. The staff has verified that the protective coatings program and SMP are included in Sections C.2.6.1 and C.2.6.3 of the LRA as applicable aging management programs. However, the staff noted a discrepancy between the information provided in Table 3.3.1-5 and Section C.2.6.7 of the LRA. Table 3.3.1-5 lists the protective coatings program and structural monitoring program as the aging management programs for panel joint seals and sealants, however, Section C.2.6.7 of the application does not list protective coatings program as the aging management program for the components. In its submittal of October 10, 2000, responding to the staff's RAI 3.6-27, the applicant stated that Table 3.3.1-5 should not have credited the protective coatings program as an aging management program for the panel joint seals and sealants. The applicant stated that the SMP manages the aging of the panel joint seals and sealants. This is acceptable to the staff.

Tables 3.3.1-3 through 3.3.1-5 and Tables 3.3.1-8 through 3.3.1-13 of the LRA do not list prestressed concrete structural components. RAI 3.6-30 asked the applicant to confirm that Plant Hatch has no prestressed concrete structural elements in its structures that are subject to an AMR. Otherwise, list the prestressed concrete elements subject to an AMR and discuss applicable AMPs for managing their aging effects. The applicant stated that the only prestressed elements in the plant are precast concrete wall panels on the outside of the reactor building, turbine building, and control building. The panels on the outside of the turbine building and control building are for architectural purposes. The precast concrete wall panels around the fuel-handling area of the refueling floor of the reactor building above elevation 228 ft.-0 in. are provided to protect the refueling floor from the outside environment. The panels outside the reactor building have concrete and embedded steel, which are listed in the tables mentioned in the RAI. The SMP is the AMP applicable to the precast panels. This clarification closes RAI 3.6-30.

The tables in Section 3.3.1 of the LRA do not list masonry walls as structural components requiring aging management review, although Section C.1.4.2 of the LRA identifies cracking of masonry block walls as an applicable aging effect for block walls within the reactor building, control building, and main stack. RAI 3.6-47 asked the applicant to discuss in detail its intent to manage the aging effects of these masonry walls and describe how the AMP for periodic inspection and surveillance of these masonry walls incorporates the insights provided in NRC IN 87-65, "Lessons Learned from Regional Inspection of Applicant Actions in Response to IE Bulletin 80-11." The applicant stated that NRC IE Bulletin 80-11 "Masonry Wall Design," indicated that, in many instances, masonry block walls had inadequate structural strength to resist pipe support, equipment, and seismic loads. This bulletin required (1) identification of masonry walls, which are in close proximity to, or have attachments from, safety-related piping or equipment, and (2) a re-evaluation of the design adequacy and construction practices. According to the IE bulletin, the masonry block wall problems resulted primarily from design and construction deficiencies, rather than from potential long-term aging degradation mechanisms. In responding to the bulletin, the applicant evaluated the as-built conditions of the subject masonry block walls. Walls were prioritized by considering the relative potential for wall failure based on wall configuration loading magnitudes and span lengths. Detailed re-evaluations were performed for the worst case walls. A relatively large number of the lesser-case walls were also re-evaluated in detail to assure the structural adequacy of each, and to assure that a sufficiently large sample was selected to include all walls requiring a detailed re-evaluation. The remainder of the lesser-case walls in each priority were re-evaluated by comparison with the worst-case walls. This assured that the most critical walls were considered for prompt, detailed re-evaluation. The NRC concluded that SNC had appropriately complied with the requirements of the bulletin, and no further action was required beyond the normal inspections and evaluations committed to in response to the bulletin. NRC also revisited Plant Hatch to assure proper maintenance of the block walls per the requirements of IE Bulletin 80-11. The applicant stated that masonry block wall cracks may be caused by age-related degradation mechanisms. During one walkdown, performed as part of the SMP, cracking was observed in concrete masonry block walls. The applicant considered the observed cracks to be minor and insignificant, and were noted for comparison in future walkdowns.

The applicant also indicated that its SMP is intended to manage the aging effects of the block walls discussed above during the period of extended operation. Although the applicant's response did not specifically describe how the SMP incorporated the insights provided in NRC IN 87-65, the staff considers that by describing the past masonry wall walkdown experience and disposition of walkdown findings, the applicant has adequately responded to the intent of RAI 3.6-47. Thus, the staff considers the RAI resolved.

With the applicant's clarification that the SMP will be used to manage aging effects of block walls during the period of extended operation, and with the information provided by the applicant concerning its experience in using the SMP to identify age-related degradation of the block walls, the staff concludes that the SMP will be adequate to identify age-related degradation of block walls during the period of extended operation.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the reactor building will be adequately managed by the above listed AMPs.

Reactor Building Penetrations

Aging management programs determined by the applicant to manage aging effects requiring management for reactor building penetrations are:

- protective coatings program
- structural monitoring program

The protective coatings program provides for periodic inspection of structural component surfaces, including fasteners and associated coatings. This program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion.

The structural monitoring program provides for the visual inspection of structural components on a scheduled basis. The SMP will inspect structural components for loss of material due to general corrosion.

The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

A complete discussion of the applicable aging management programs may be found in Section 3.1 of this SER.

The applicant has identified the above listed programs for managing the aging of reactor building penetrations.

Tables 3.3.1-1 through 3.3.1-13 of the LRA do not list fire barrier penetration seals as components subject to an AMR. The staff views these fire barrier penetration seals as within scope and subject to an AMR. RAI 3.6-35 asked the applicant to describe how the aging effects for fire barrier penetration seals are evaluated, and to discuss the AMP used to adequately manage the effect. The applicant stated that fire barrier penetration seals are addressed in LRA Table 3.2.4-18. Aging effects requiring management are listed as loss of material, change in material properties, and cracking in LRA Section C.2.3.4.1 and fire protection activities is designated as the AMP to manage these aging effects. The staff finds this response acceptable. RAI 3.6-35 is closed.

In response to RAI 3.6-45 related to the five-operating-cycle inspection period in the SMP, the applicant stated that the baseline inspection was conducted in 1998, and the next inspection is due in 2003. Thereafter the inspection period will be every five operating cycles. The SMP has criteria and guidance for adjusting the inspection interval based on the results of inspection. Considering the LCO and surveillance requirements related to secondary containments in TS Section 3.6.4.1, the staff finds the above inspection interval criteria for reactor building penetrations acceptable and RAI 3.6-45 is closed.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups associated with the reactor building penetrations will be adequately managed by the above listed AMPs.

Turbine Building

The applicant stated that the aging management programs determined to manage aging effects requiring management for the turbine building are:

- protective coatings program
- structural monitoring program

The SMP inspection process assesses the overall conditions of the listed structures, and identifies any degradation. The SMP will inspect the concrete commodities for loss of material, cracking, and spalling. The SMP will also visually inspect masonry block walls for cracking.

The protective coatings program provides for periodic inspection of structural component surfaces, including fasteners and associated coatings. This program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion.

The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the turbine building will be adequately managed by the above listed AMPs.

Yard Structures

The applicant stated that the aging management programs determined to manage aging effects requiring management are as follows:

- protective coatings program
- structural monitoring program

The SMP inspection process assesses the overall conditions of the listed structures, and identifies any degradation. The SMP will inspect the concrete commodities for loss of material.

The protective coatings program provides for the prevention and mitigation of corrosion of embedded steel at the surface of the concrete.

The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the yard structures will be adequately managed by the above listed AMPs.

3.6.4 Conclusion

The staff has reviewed the information in Section 2.4, "Structures Screening Results"; Section 3.3.1, "Civil Structural Components"; A.1, "Existing Programs and Activities"; A.2, "Enhanced Programs and Activities"; A.3, "New Programs and Activities"; B.1, "Existing Programs and Activities"; B.2, "Enhanced Programs and Activities"; B.3, "New Programs and Activities"; and C.2.6, "Aging Management Review for Civil Discipline Commodities" of the LRA. On the basis of this review, the staff concludes that the applicant has adequately identified the aging effects associated with structures and structural components and has demonstrated that the aging effects associated with the structures and structural components will be adequately managed so that there is reasonable assurance that these structures and structural components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.7 Electrical and Instrumentation and Controls

The applicant described its AMR for electrical components at Plant Hatch in Section C.2.5, "Aging Management Reviews For Electrical Discipline Commodities" of the LRA. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effects of aging on the electrical components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.7.1 Summary of Technical Information in the Application

Section C.1.3 of the LRA identified the applicable aging effects for electrical components. The process to determine aging effects applicable to electrical components began with an understanding of the aging effects identified in the industry literature. The components that require aging management were determined by examining the component materials, service environments, and operating stresses for each component type. In addition to the industry literature review, plant-specific operating experience was reviewed to provide reasonable assurance that all aging effects were identified for the AMR.

External environments are defined in Sections C.1.2.8, "Inside;" C.1.2.9, "Outside;" and C.1.2.10, "Buried or Embedded" of the LRA. "Inside" external environments are defined as environments where equipment is sheltered from the weather. "Outside" external environments are defined as environments found outside a structure where equipment would not be sheltered from the weather. "Buried or embedded" external environments are defined as environments beneath the surface of the ground (in some cases with controlled backfill) or embedded in structural concrete. Structures and components which perform their functions in external environments are, in general, discussed in Sections C.2.1, C.2.2, C.2.3, C.2.4, C.2.5, and C.2.6 of the LRA, and are evaluated in Sections 3.6 and 3.7 of this SER, unless otherwise noted.

3.7.1.1 Effects of Aging

Electrical cables, connectors, splices, terminal blocks, Nelson frames, and phase bussing are the electrical component types that are subject to an AMR. Based on available industry literature, the following aging effects have been identified for these electrical components requiring aging management:

- loss of material
- cracking/embrittlement
- loss of conductivity
- change in insulation resistance
- change in material properties

Depending upon the environmental conditions that are present, the above aging effects can be expected to occur due to the following aging mechanisms:

- thermal degradation of organic materials

    - loss of material
    - cracking/embrittlement
    - change in material properties
    - change in insulation resistance

- thermoxidative degradation

  - loss of material
  - cracking/embrittlement
  - change in material properties
  - change in insulation resistance

- radiolysis of organic materials

  - cracking/embrittlement
  - change in insulation resistance
  - change in material properties

- water treeing

  - change in insulation resistance

The aging effects associated with nonmetallic materials used in electrical components at Plant Hatch were assessed by evaluating the environmental conditions associated with high temperature, radiation, and moisture. High temperature can result in thermal degradation and thermoxidative degradation of electrical components. A radiation environment can result in radiolysis of organic materials. Water penetration into electrical cable insulation can result in reduced dielectric strength due to increased conductivity of the insulation caused by increased ion mobility and concentration.

3.7.1.2 Aging Management Programs

On the basis of the review of industry literature and plant-specific operating experience, the applicant maintains that, with the exception of the 4-kV power and transformer feeder cables and insulated cables, connectors, splices, and terminal blocks, the aging effects identified above for Nelson frames and phase bussing do not require an aging management program.

3.7.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in Sections 3.4, A.1.16, C.1.3, and C.2.5 of the LRA regarding the applicant's demonstration that aging effects will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation for the electrical components. After completing the initial review, the staff issued requests for additional information on July 14 and July 28, 2000. The responses were received on October 10, 2000 and January 31, 2001.

3.7.2.1 Effects of Aging

The applicant identified potential aging effects for license renewal by reviewing available industry literature and plant-specific operating experience. These effects include loss of material, cracking/embrittlement, change in material properties, and change in insulation resistance. The staff evaluated the applicant's identification of these potential aging effects for the phase bussing, Nelson frames, cables, splices, connectors, and terminal blocks.

3.7.2.1.1 Aging Effects on Phase Bussing Caused by High Temperature and Radiation

The materials associated with the phase bussing include various polymers, galvanized and stainless steel, and tinned and bare copper. Phase bussing is subjected to an internal environment due to "self heating," and an external environment of "inside" (excluding containment). Inside environments are defined in Section C.1.2.8 of the LRA as environments where equipment is sheltered from the weather. The phase bussing inside environment is associated with the electrical bus between the 4160/600 volt station auxiliary transformer CD and 600v buses C and D.

A review of operating experience based on the condition reporting database identified that approximately 122 deficiencies had been written on the power transformer system associated with phase bussing. The applicant screened these deficiencies to determine which ones might be potentially age-related. No age-related failures of the in-scope phase bussing components were found.

The materials of construction for the portion of phase bussing that is in scope were evaluated for 60-year temperatures and radiation doses based on industry material databases. The 60-year temperatures and allowable doses were greater than the expected temperatures and radiation doses in all cases. Therefore, no aging effects associated with temperature and radiation require aging management for in-scope electrical phase bussing.

The staff agrees with the applicant's assessment and conclusion that, on the basis of the review of industry information, plant-specific operating experience, and evaluation of the materials of construction for 60-year expected temperatures and radiation doses, no aging effects that would lead to a loss of intended function are applicable for phase bussing, and no AMP is necessary.

3.7.2.1.2 Aging Effects on Nelson Frames

The materials associated with Nelson frames consist of various polymers and galvanized and painted steel. Nelson frames are located in the walls and floors of the reactor building with an external environment of "inside" (excluding containment). Nelson frames are located in the wall between the reactor building and turbine building, in the wall between the reactor building and the control building, and between floors of the reactor building. Reactor building electrical penetrations allow cables to penetrate the secondary containment boundary and maintain secondary containment leakage rates within design limits.

A review of the condition reporting database did not identify any deficiencies of the reactor building penetration system, which contains the Nelson frames. The materials of construction for the Nelson frames were evaluated for 60-year temperatures and radiation doses based on industry material databases. The 60-year temperatures and allowable doses were greater than the expected temperatures and radiation doses in all cases. Therefore, no aging effects associated with temperature and radiation require aging management for Nelson frames.

The staff agrees with the applicant's assessment and conclusion that, on the basis of the review of industry information, plant-specific operating experience, and evaluation of the materials of construction based on 60-year expected temperatures and radiation doses, no aging effects that would lead to a loss of intended function are applicable for Nelson frames, and no AMP is necessary.

3.7.2.1.3 Aging Effects on Cables, Connectors, Splices, and Terminal Blocks

The aging effects discussed in this subsection are associated with cables, connectors, splices, and terminal blocks that are not managed by the applicant's environmental qualification program. The applicant's aging management of environmentally qualified cables, connectors, splices, and terminal blocks is considered a TLAA and is discussed in Section 4.4 of the LRA. The staff's evaluation of this section can be found in Section 4.4 of this SER.

The materials associated with cables, connectors, splices, and terminal blocks consist of various polymers, tinned and bare copper, and galvanized and stainless steel. Insulated electrical cable at Plant Hatch is located in an external environment of "inside" and "outside." Some cables could be exposed to submergence. Electrical splices, connectors, and terminal blocks are located in an external environment of "inside" and "outside," and are installed throughout the plant, in the drywell, and in outdoor pits.

The effects of moisture on medium-voltage cables can result in water trees when the insulating materials are exposed to long-term, continuous-voltage stress and moisture, eventually resulting in breakdown of the dielectric and failure. The growth and propagation of water trees are somewhat unpredictable, and few occurrences have been discovered for cables operated below 15 kV. Water treeing has been documented for medium-voltage electrical cables with cross-linked-polyethylene (XLPE) or high-molecular-weight polyethylene (HMWPE) insulation. Recently, medium-voltage cables with ethylene propylene rubber insulation have failed after being exposed to long-term, continuous-voltage stress and significant moisture. Plant Hatch wetted cable activities provide for mitigating activities as well as condition monitoring activities for 4-kV power cables and transformer feeder cables that are within the scope of license renewal. Wetted cables activities are discussed in Section B.1.16 of the LRA. The staff's review of wetted cables activities can be found in Section 3.1.16 of this SER.

Radiation-induced degradation in cable jacket and insulation materials produces changes in organic material properties, including reduced elongation, and changes in tensile strength. Visual indications of radiative aging may include embrittlement, cracking, discoloration, and swelling of the jacket and insulation. For cables, connectors, splices, and terminal blocks, the applicant has provided an "Insulated Cables and Connections Aging Management Program," by letter dated January 31, 2001. The staff's evaluation of this AMP can be found in Section 3.1.30 of this SER.

Thermal-induced degradation in cable jacket and insulation materials can result in reduced elongation and changes in tensile strength. Visible indications of thermal aging may include embrittlement, cracking, discoloration, and swelling of the jacket and insulation. The Arrhenius methodology was used by the applicant for temperatures corresponding to a 60-year service life for cables, connectors, splices, and terminal blocks. These temperatures were compared to the maximum bounding temperatures of the various plant areas. For cables, connectors, splices, and terminal blocks, the applicant has provided an "Insulated Cables and Connections Aging Management Program," by letter dated January 31, 2001.

The staff agrees with the applicant's assessment regarding the wetted cable activities for moisture for the 4-kV power cables and transformer feeder cables and with the applicant's assessment associated with temperature and radiation for cables, connectors, splices, and terminal blocks.

3.7.2.2 Aging Management Programs

3.7.2.2.1 Aging Management Program for Wetted Cables

The wetted cable activities at Plant Hatch provide for mitigating activities as well as condition monitoring activities. Plant Hatch wetted cables activities include monitoring for and removing water, along with testing to detect changes in insulation resistance. Several 4-kV power cables and transformer feeder cables within the scope of license renewal are routed through the underground duct bank system consisting of outdoor pull boxes containing underground conduits routed between in-scope buildings. Change in insulation resistance is the aging effect that is mitigated and monitored by the wetted cable activities.

The water level is measured, recorded, and the pull boxes drained where these in-scope 4-kV power and transformer cables are routed. Megger and polarization index testing are periodically performed. When new terminations are made, the cables are hipot tested to provide additional assurance that the cable insulation integrity is sound. In addition, the pull boxes are drained quarterly and testing is performed on in-scope 4-kV motor windings and the associated feeder cables during regular motor and pump maintenance tasks.

The wetted cable activities meet the intent of IEEE 43-1974, "Recommended Practice for Testing Insulation Resistance of Rotating Machinery"; and IEEE 95-1977," Recommended Practice for Insulation Testing of Large AC Rotating Machinery with High Direct Voltage." Pull boxes found to contain water are drained to 1 inch of water or less. Cables and loads must successfully pass megger and polarization index testing. Corrective actions are taken if testing results are unacceptable. Plant specific operating experience did not identify any in-scope age-related cable failures due to moisture intrusion.

The staff finds that the Plant Hatch wetted cable activities manage the effects of cable aging due to moisture intrusion so that the intended functions will be maintained consistent with the CLB for the period of extended operation (see Section 3.1.16 of this SER).

3.7.2.2.2 Aging Management Program for Cable, Connectors, Splices, and Terminal Blocks

Sections 3.4, C.1.3, and C.2.5 of the LRA conclude that no aging effects associated with high temperature and radiation require aging management for cables, connectors, splices, and terminal blocks. On July 14, 2000, the staff issued RAI 2.5 requesting that the applicant provide a description of the following:

- an aging management program for accessible and inaccessible electrical cables and connections that may be exposed to an adverse localized environment caused by heat or radiation

- an aging management program for accessible and inaccessible electrical cables used in instrumentation circuits that are sensitive to a reduction in conductor insulation resistance exposed to an adverse localized environment caused by heat or radiation

By letter dated October 10, 2000, the applicant acknowledged that industry information exists regarding the effects of temperature and radiation on electrical cables and connections, including the information on cable aging in the staff's Generic Aging Lessons Learned (GALL) Report. By letter dated January 31, 2001, the applicant provided a description of an "Insulated Cables and Connections Aging Management Program." The insulated cables and connections AMP is a condition monitoring program designed to confirm that age-related degradation is not inhibiting component function of insulated cables and connections within the scope of license renewal during the period of extended operation. The staff evaluation of this AMP is found in Section 3.1.30 of this SER.

The staff finds that the Plant Hatch insulated cables and connections AMP manages the effects of aging due to radiation and temperature so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

3.7.3 Conclusion

The staff has reviewed the information in Sections 3.4, A.1.16, C.1.3, and C.2.5 of the LRA as well as the additional information provided by the applicant in RAI response dated October 10, 2000, and by letter dated January 31, 2001. On the basis of this review, the staff concludes that the applicant has adequately identified the aging affects associated with electrical components, and has demonstrated that the aging effects associated with electrical systems and components at Plant Hatch will be adequately managed so that there is reasonable assurance that these systems and 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).