Lewis Sumner
Vice President
Hatch Project Support

Southern Nuclear
Operating Company, Inc.
40 Inverness Parkway
Post Office Box 1295
Birmingham, Alabama 35201

Tel 205.992.7279
Fax 205.992.0341

SOUTHERN COMPANY
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October 10, 2000

HL-6002

Docket Nos. 50-321
50-366

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

Edwin I. Hatch Nuclear Plant
Response To License Renewal Requests for Additional Information

Ladies and Gentlemen:

By letters dated July 14, 2000 and July 28, 2000, the NRC requested additional information related to the review of the license renewal application for the Edwin I. Hatch Nuclear Plant, Units 1 and 2. By letter dated August 29, 2000, Southern Nuclear Operating Company (SNC) provided responses to all requests for additional information (RAIs) related to Section 2 of the application. By this letter, SNC submits responses to the remaining RAIs. The responses are found in Attachment 1 to this letter.

Many of the RAIs related to aging management programs asked for the same type of information for each program. Existing application Appendices A and C provided information on these programs. However, during discussions between SNC and the NRC staff, it was decided that these RAIs could most efficiently be answered by collecting program information from Appendices A and C, and grouping the information into another document, which SNC has labeled Appendix B. The detail in Appendix B was also expanded in some instances to address specific RAIs. This Appendix is provided as a part of Attachment 1 to this letter.

If you have any questions regarding this matter, please contact R. D. Baker at (205) 992-7367.

Respectfully submitted,

Lewis Sumner

H. L. Sumner, Jr.

HLS/JAM

Enclosure: Attachment 1 - Response to Requests for Additional Information Related to Aging Management Reviews and Aging Management Programs, Dated July 14, 2000 and July 28, 2000

A083

cc: Southern Nuclear Operating Company
Mr. P. H. Wells, Nuclear Plant General Manager
Mr. C. R. Pierce, License Renewal Services Manager
SNC Document Management (R-Type A02.001)

U. S. Nuclear Regulatory Commission, Washington, D.C.
Mr. C. I. Grimes, Branch Chief, License Renewal and Standardization Branch
Mr. L. N. Olshan, Project Manager - Hatch
Mr. W. F. Burton, Project Manager - Hatch License Renewal

U. S. Nuclear Regulatory Commission, Region II
Mr. L. A. Reyes, Regional Administrator (w/o enclosure)
Mr. J. T. Munday, Senior Resident Inspector – Hatch

ATTACHMENT 1

EDWIN I. HATCH NUCLEAR PLANT

DOCKETS 50-321, 50-366

OPERATING LICENSES DPR-57, NPF-5

LICENSE RENEWAL APPLICATION

RESPONSE TO REQUESTS FOR ADDITIONAL INFORMATION

RELATED TO AGING MANAGEMENT REVIEWS

AND AGING MANAGEMENT PROGRAMS

DATED JULY 14, 2000 AND JULY 28, 2000

Table of Contents

I. INTRODUCTION

By letters dated July 14, 2000 and July 28, 2000, the Nuclear Regulatory Commission (NRC) requested additional information (RAI) from Southern Nuclear Operating Company (SNC) to support the review and approval of the E. I. Hatch Nuclear Plant License Renewal Application (LRA). This attachment provides SNC's responses to the RAIs related to Sections 3 and 4, and Appendices A, C, and E of the application. Section 3 of the LRA presented tabular summaries of the results of the AMRs along with the applicable AMPs. Section 4 presented the Time-Limited Aging Analyses for Plant Hatch. Appendix A provided summary descriptions of the credited aging management programs, and a summary of the TLAAs. Appendix C provided an evaluation of the aging effects requiring management, and aging management reviews for each combination of component material type and environment. Appendix E provided proposed Technical Specifications changes. Information pertinent to certain reactor vessel RAIs is also contained in Appendix E.

The entire SNC response to each RAI is contained in this document. Based on NRC guidance, the annual update of the LRA will only contain changes that result from changes to the current licensing basis (CLB) of Plant Hatch.

II. ACRONYMS AND ABBREVIATIONS

The acronyms or abbreviations in Table 1 are used throughout the RAI responses. Acronyms or abbreviations used by NRC in the RAIs have not been added to this list. Because the process of RAI and response is, by its nature, repetitive, the usual approach of spelling out the phrase for an acronym or abbreviation the first time is not used. Table 1 presents the acronyms and abbreviations that are used throughout this document.

Table 1
Acronyms and Abbreviations

AMP	*Aging management program or activity*
AMR	*Aging management review*
ANS	*American Nuclear Society*
ANSI	*American National Standards Institute*
ASME	*American Society of Mechanical Engineers*
BTP	*Branch Technical Position*
BWR	*Boiling Water Reactor*
BWRVIP	*Boiling Water Reactor Vessel and Internals Project*
CCTLP	*Component cyclic or transient limit program*
CCW	*Closed-cooling water*
CLB	*Current licensing basis*
CFR	*Code of Federal Regulations*
CRD	*Control rod drive*
CST	*Condensate storage tank*
CUF	*Cumulative usage factor*
DWST	*Demineralized water storage tank*
ECCS	*Emergency core cooling system(s)*
ECP	*Electro-chemical potential/electro-chemical corrosion potential*
EDG	*Emergency diesel generator*
EFPY	*Effective full power years*
EHC	*Electro-hydraulic control*
EPIX	*Equipment Performance Information Exchange*
EPR	*Ethylene propylene rubber*
EPRI	*Electric Power Research Institute*
EQ	*Equipment qualification*
ERR	*Event Review Report*
FAO	*Free available oxidant*
FHA	*Fire Hazards Analysis*
FSAR	*Final Safety Analysis Report (also Updated Final Safety Analysis Report)*
FAC	*Flow-accelerated corrosion*
FAO	*Free available oxidant*
GALL	*Generic Aging Lessons Learned (NRC report)*
GE	*General Electric*
GL	*Generic Letter*
GSCI	*Gas System Components Inspections*
HPCI	*High pressure coolant injection*
HVAC	*Heating, ventilation, and air conditioning*
HWC	*Hydrogen water chemistry*

Table 1 (Continued)
Acronyms and Abbreviations

IASCC	*Irradiation-assisted stress corrosion cracking*
IGA	*Intergranular attack*
IGSCC	*Intergranular stress corrosion cracking*
ILRT	*Integrated leak-rate test*
INPO	*Institute of Nuclear Power Operations*
IR	*Information Report*
ISI	*In-service inspection*
ISP	*Integrated surveillance program*
LER	*Licensee Event Report*
LPCI	*Low pressure coolant injection*
LRA	*License renewal application*
MCC	*Motor Control Center*
MCR	*Main control room*
MCRECS	*Main Control Room Environmental Control System*
MIC	*Microbiologically induced corrosion*
MPL	*Master parts list*
MSIV	*Main steam isolation valve*
NEI	*Nuclear Energy Institute*
NFPA	*National Fire Protection Association*
NMCA	*Noble metal chemical addition*
NPDES	*National Pollutant Discharge Elimination System*
NPRDS	*Nuclear Plant Reliability Database System*
NPS	*Nominal pipe size*
NRC	*Nuclear Regulatory Commission*
NS&C	*Nuclear Safety and Compliance*
NSAC	*Nuclear Safety Analysis Center*
NSOA	*Nuclear Safety Operational Analysis*
NSSS	*Nuclear steam supply system*
PCCW	*Primary containment chilled water*
PCIA	*Passive Components Inspection Activities*
PI	*Polarity index*
PSW	*Plant service water*
PUAR	*Plant Unique Analysis Report*
PVRC	*Pressure Vessel Research Council*
QA	*Quality assurance*
RAI	*Request for additional information*
RBCCW	*Reactor building closed cooling water*
RCIC	*Reactor core isolation cooling*
RCPB	*Reactor coolant pressure boundary*
RCS	*Reactor coolant system*
RHR	*Residual heat removal*
RHRSW	*Residual heat removal service water*
RICSIL	*Rapid Information Communication Service Information Letter*
RPV	*Reactor pressure vessel*
RT	*Radiographic testing*
RWCU	*Reactor water cleanup*
SCC	*Stress corrosion cracking*
SER	*Safety evaluation report*

Table 1 (Continued)
Acronyms and Abbreviations

SGTS	*Standby Gas Treatment System*
SIL	*Service Information Letter*
SLC	*Standby liquid control*
SMP	*Structural monitoring program*
SNC	*Southern Nuclear Operating Company*
SRP	*Standard Review Plan*
SRV	*Safety-relief valve*
SSC	*System, structure, or component*
TLAA	*Time-limited aging analysis*
TRO	*Total residual oxidant*
TTA	*Tolytriazole*
TWSPI	*Treated Water System Piping Inspections*
USAS	*United States of America Standard*
USE	*Upper shelf energy*
UT	*Ultrasonic testing*

III. RAI RESPONSES

During the initial review of the Plant Hatch LRA, SNC and NRC discussed the desirability of collecting the program-related information into a common document. The LRA presented program-related information both in Appendix A and Appendix C. The program summaries were presented in Appendix A, whereas significant details regarding program implementation and programmatic coverage were contained in the various Appendix C.2 commodity group evaluations. Within each Appendix C.2 commodity group evaluation, SNC presented tables relating each aging effect relevant to the commodity to the program or programs credited for managing the aging effect in the renewal term. These tables were in a format consistent with the ten attributes for AMPs in the NRC draft SRP for license renewal.

As discussed with NRC, SNC has produced a stand-alone document as an aid to the efficient and expeditious review of the Plant Hatch LRA. This "Appendix B" document was produced to collect the information, at the level of detail contained in the LRA, related to the AMPs credited for license renewal. In some instances, a greater level of detail is provided in Appendix B than was provided in the LRA. Generally, this greater detail is in response to specific RAIs. Thus, Appendix B contains the responses to many of the program-related RAIs. The RAI responses are organized so that the individual RAI responses refer to Appendix B when the information requested is addressed there. Further clarification beyond the level of detail discussed with NRC as being appropriate for Appendix B is provided in specific RAI responses, as necessary.

RAI responses related to Appendix B or LRA Appendix A programs are found in section IV of this RAI Response document. The remaining RAI responses are found in section V of this document. Appendix B is found in section VI.

IV. AGING MANAGEMENT PROGRAM-RELATED RAI RESPONSES

GENERAL PROGRAM RELATED RAIS

RAI 3.1-1:

Provide specific details regarding the use of industry (EPRI/NEI)/NRC guidelines for the AMPs.

If an industry/NRC guideline is being used to manage a program, then specific details regarding how the guideline is being utilized, whether the guideline is being used partially or entirely, and how the guideline is managing the aging effects of that program should be discussed.

RESPONSE TO RAI 3.1-1:

See Appendix B. Specific aspects of industry guidance relevant to aging management are provided in the applicable Appendix B AMP descriptions. However, it should be noted that this RAI is inconsistent with previous direction given to SNC by the NRC Staff in a January 7, 2000 public meeting. In that meeting, the NRC Staff specifically stated that the LRA need not contain any specific details of the EPRI water chemistry guidelines; the commitment to use the EPRI water chemistry guidelines only need be stated in the application.

RAI 3.1-2:

How the parameters are being measured/monitored relative to aging effects was not provided. Provide the parameters to be measured/monitored for each AMP and discuss how the parameters adequately identify the aging effect.

RESPONSE TO RAI 3.1-2:

See Appendix B. Monitored parameters, such as chemistry parameters and visual inspection items specific to a program, are specified in each AMP description, as applicable.

RAI 3.1-3:

Provide the sampling (inspection/monitoring) frequencies for each parameter measured in each AMP.

RESPONSE TO RAI 3.1-3:

See Appendix B. Inspection or monitoring frequencies are specified when the frequency does not appear in an industry guidance document. Inspection frequencies may be based on operating experience where applicable. When a frequency is found in an accepted industry guidance document, reference is made to that document for inspection frequencies.

RAI 3.1-4:

Acceptance Criteria

Provide acceptance criteria for each measured parameter in each AMP.

RESPONSE TO RAI 3.1-4:

See Appendix B. For new programs or one-time inspections, the specific acceptance criteria for the program are presented in the AMP description and discussed. Acceptance criteria are also provided for existing and enhanced programs that are not part of industry initiatives. When acceptance criteria are contained in accepted industry guidance documents, reference is made to those documents for a discussion of acceptance criteria.

RAI 3.1-5:

Operating Experience

For each program, provide a discussion regarding industry operating experience that may be applicable to Hatch. More specifically, a discussion regarding how the program works at Hatch and how future operating experience at other plants will be monitored by Hatch should be provided.

If the AMP is a generic industry program (i) there should be a description of the industry experience in mitigating or eliminating the aging effect using the AMP, and (ii) there should be a description regarding the program for monitoring and evaluating the effectiveness of the industry programs.

RESPONSE TO RAI 3.1-5:

See Appendix B. Operating experience, including past corrective actions resulting in program enhancements or additional programs, is discussed in each AMP description. Plant-specific operating experience, originating from a review of corrective actions program activities is presented for each program. In many cases, industry guidance is used to develop the specific aspects of an AMP. Industry-wide operating experience was considered in the development of this guidance, and its use insures that industry experience is considered in managing aging effects associated with the program. Reference is made to the specific industry document for a discussion of industry experience in these cases.

RAI 3.1-6:

Scope

The staff identified that most, if not all, of the AMP descriptions contained in Appendix A of the application do not clearly identify the scope of the program (what systems and components require the program to manage an aging effect). For each AMP, provide descriptions which clearly identify the systems (and components, if appropriate) that fall within the scope of the AMP.

RESPONSE TO RAI 3.1-6:

See Appendix B. Each specific system, or part of a system for which a particular AMP is used to manage aging effects, is listed for each AMP description. Discussion of specific components is usually not found in the AMP descriptions. Refer, instead, to the appropriate LRA Section 3 table and Appendix C.2 commodity group for specific component-related information.

RAI 3.1-7:

Revise the description of the AMPs and activities in Appendix A to clearly identify for each AMP and activity (1) the scope of the program, (2) actions to prevent or mitigate aging, (3) parameters monitored or inspected, (4) how aging effects will be detected, (5) how the parameters will be monitored and trended, (6) the acceptance criteria against which the need for corrective action will be evaluated, and the basis for the acceptance criteria, (7) the corrective actions to be taken when the acceptance criteria are not met, (8) the confirmation process used to ensure that the preventive actions are adequate, (9) administrative controls used to provide a formal review and approval process, and (10) plant-specific and industry-wide operating experience relevant to the AMP or activity that has, or may result in, enhancements or additional programs. The bases and the plant-specific information pertaining to the ten key elements identified above in each AMP should be described and discussed in detail. Some of these items may be repeated (with further detail) in the following pages.

RESPONSE TO RAI 3.1-7:

See the responses to RAIs 3.1-1 through 3.1-6. Also, see Appendix B. Items (7) corrective actions, (8) confirmation process, and (9) administrative controls used to provide a formal review and approval process are addressed through the corrective actions program. This AMP provides the framework whereby corrective actions are initiated as a result of any deficiency discovered during the performance of license renewal program activities. The corrective actions program also provides a means to confirm that corrective and preventive actions are accomplished and adequate, and provides administrative controls for a formal review and approval process. The corrective actions program provides for the control of plant procedures and records associated with AMPs. These controls include a formal review and approval process.

REACTOR WATER CHEMISTRY CONTROL

RAI 3.1.1-1:

In Section A.1.1.1 of the LRA, it is stated that water chemistry control helps decrease flow-accelerated corrosion (FAC) in the reactor coolant system, as well as in the balance of plant systems. Provide detailed information, including the technical basis, that explains how this is achieved for carbon steel components.

RESPONSE TO RAI 3.1.1-1:

The statement in Section A.1.1.1 of the Plant Hatch LRA is incorrect. Reactor water chemistry control currently includes hydrogen injection to reduce the concentration of oxidizing species such as oxygen. Reduced concentrations of oxidizing species protect stainless steel components in the reactor coolant system. However, some very low oxygen levels which can exist in a BWR reactor coolant environment are detrimental to the formation of protective oxide layers in carbon steels, which can result in increased carbon steel corrosion rates. Loss of material in carbon steel piping components resulting from FAC is managed by the FAC program, as presented in LRA Sections C.2.1.1.3 and C.2.2.1.1.

RAI 3.1.1-2:

The staff understands that hydrogen water chemistry (HWC) and noble metal chemistry addition (NMCA) have been implemented in both Hatch Units. However, such controls were not discussed or mentioned in Section A.1.1 of the LRA. The staff also notes that in the AMRs of commodity groups in Appendix C, credit is taken in managing the aging effects due to cracking and loss of materials based on hydrogen injection to minimize the oxygen content in the reactor water. Seven commodity groups are identified to be exposed to the reactor water environment. Revise Section A.1.1 of the LRA to identify the reactor water chemistry control by HWC and NMCA and describe how this is implemented, controlled and monitored for its effectiveness.

RESPONSE TO RAI 3.1.1-2:

The Appendix C paragraph referenced by RAI-3.1.1-2 states that management "...can be accomplished through the use of filter/demineralizers that limit impurities within the feedwater and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core."

The intent of this paragraph was to provide a description of how Plant Hatch has implemented EPRI TR-103515, Rev. 1, "BWR Water Chemistry Guidelines," and plans to implement chemistry controls to meet the applicable acceptance criteria contained in EPRI TR-103515, Rev. 2. This information was not intended to commit Plant Hatch to a specific acceptable water chemistry mode for compliance with applicable acceptance criteria contained in EPRI TR-103515. Plant Hatch is committed to meet the chemistry control parameters specified for RCS chemistry in EPRI TR-103515. The current revision of EPRI TR-103515 allows for both HWC operation, with or without NMCA, and normal water chemistry operation. SNC is currently updating the Plant Hatch water chemistry program to Revision 2 of EPRI TR-103515.

See Appendix B, Section 1.1, for additional information on HWC and NMCA implementation.

RAI 3.1.1-3:

Under the conditions of HWC and NMCA, the oxygen content in the reactor water is expected to be very low which is desirable in mitigating intergranular stress corrosion cracking (IGSCC) in stainless steel. However, this low oxygen condition may be detrimental to the corrosion resistance of components made of carbon steel, particularly, for the aging effect of erosion-corrosion or FAC. Describe, in detail, any existing mitigating or preventive program that will mitigate this low oxygen condition, such as, injecting oxygen into the affected systems to improve the resistance to erosion-corrosion in carbon steel components. Provide justification if you do not have such a program.

RESPONSE TO RAI 3.1.1-3:

Tables C.2.1.1-10 and C.2.2.1-2 of the Plant Hatch LRA indicate that no mitigation program is credited for FAC at Plant Hatch. No program is required to mitigate FAC in RCS components, based on the following information:

- Industry data regarding FAC inspections and the recommendations of EPRI NSAC 202L, "Recommendations for an Effective Flow-Accelerated Corrosion Program," indicate that the components most susceptible to FAC are located in nonsafety-related steam systems outside of the scope of license renewal (such as heater drains and extraction steam).

- Additionally, inspections designed to detect loss of material due to FAC prior to loss of component function are proposed in the LRA for in-scope components that are susceptible to FAC. As outlined in Tables C.2.1.1-10 and C.2.2.1-2, programs to inspect piping system components for FAC include the FAC program, TWSPI, and the ISI program.

See LRA Sections C.2.1.1.3, C.2.2.1.1, and Appendix A, and Appendix B, Section 2.2 of this submittal, for additional information on FAC.

RAI 3.1.1-4:

Briefly describe how the water chemistry controls are implemented in the reactor water system, the condensate/feedwater cycle, and the reactor water cleanup (RWCU) system. Detailed plant-specific information should be provided pertaining to the regular sampling, results analysis and chemistry modification. For sampling, the number and location of samples, frequency of sampling, sample expansion, and how conservative the sample is should be discussed. Regarding the results analysis, detailed information regarding the control/diagnostic parameters, methodology for analysis/measurements and accuracies should be provided. The acceptance criteria of each monitored parameter should be discussed or referenced with sufficient detail. If in-situ or on-line measurements are not performed in monitoring the control or diagnostic parameters, discuss the potential sampling line effect on the accuracy of the measurements, particularly, regarding the measurement of oxygen content and electrochemical potential (ECP).

RESPONSE TO RAI 3.1.1-4:

A significant portion of the requested information, including a discussion of sample line recombination reactions occurring subsequent to NMCA, is found in EPRI TR-103515 Rev. 2, "BWR Water Chemistry Guidelines," which has been provided to the NRC through EPRI submittals, and is currently being implemented at Plant Hatch. Much of this information is proprietary to EPRI, as evidenced by those submittals. The information provided in response to this RAI is similar to that provided by previous applicants. Additional, detailed information concerning sampling techniques and sample analyses is available on site for NRC review.

During normal power operations, reactor coolant chemistry is maintained in accordance with the minimum reactor water control parameters (Action Level 1) in EPRI TR-103515, Rev. 2. The minimum control parameters are found in Appendix B, Section 1.1. These parameters, and associated acceptance criteria, are applicable for both HWC and normal water chemistry operations.

Currently, ECP is continuously monitored by sensors in the reactor vessel drain line when hydrogen injection is in service, to verify the continued effectiveness of hydrogen injection and NMCA.

Additional chemistry parameters are monitored in associated systems in order to support efficient operations (e.g., reactor water clean up, feedwater, and condensate systems). However, rigorous monitoring of RCS chemistry parameters provides sufficient data to provide for timely detection of chemistry excursions of significance, such that reactor water clean up, feedwater, and condensate chemistry parameters need not be specifically included in the scope of the reactor water chemistry control program, as applied to license renewal. Although Rev. 1 of EPRI TR-103515 is referenced in the LRA, SNC is currently upgrading the Plant Hatch reactor coolant water chemistry program to EPRI TR-103515, Rev. 2.

RAI 3.1.1-5:

In Section 4.3 (Guideline Values for Control Parameters) of EPRI BWR Water Chemistry Guidelines, 1996 Revision, continuous measurements of conductivity, ECP and dissolved oxygen are recommended for reactor water and reactor feedwater/condensate. However, in Section A.1.1.1of the LRA, it is stated that the monitoring is based on regular sampling. Provide justification for not continuously monitoring those parameters as recommended in the referenced EPRI BWR Water Chemistry Guidelines.

RESPONSETO RAI 3.1.1-5:

The Plant Hatch chemistry program does provide for regular and continuous monitoring of reactor coolant ECP and reactor coolant conductivity during normal power operations. Reactor coolant dissolved oxygen concentration is not monitored during normal power operations, since ECP has been shown to provide a better indicator of reactor coolant oxidizing potential. The basis for this conclusion is presented in EPRI TR-103515, Rev. 2, "BWR Water Chemistry Guidelines."

Although dissolved oxygen concentration is monitored in the feedwater and condensate systems, this monitoring is not essential to the license renewal commitment for reactor water chemistry control. Continuous monitoring of ECP in the reactor coolant system and reactor vessel is adequate to provide indication that environmental conditions conducive to IGSCC or IASCC are not present. See the response to RAI 3.1.1-4 for additional information.

RAI 3.1.1-6:

Identify all the elements in the reactor water chemistry control program that deviate from the referenced EPRI BWR Water Chemistry Guidelines. Provide justification for each deviation and discuss its adequacy.

RESPONSE TO RAI 3.1.1-6:

Plant Hatch complies with the control parameters for reactor coolant chemistry as stated in EPRI TR-103515 Rev. 2, "BWR Water Chemistry Guidelines."

RAI 3.1.1-7:

Provide the bases and justification for the following items:

a. The ISI program is not referenced in the aging management of non-Class 1 carbon steel and stainless steel components within the reactor water environment (commodity groups of C.2.2.1.1 and C2.2.1.2)

b. Monitoring and trending are not necessary for timely corrective action for the loss of material (Tables C.2.2.1-1, C.2.2.1-3 and C.2.2.1-4) and IGA/SCC (Tables C.2.1.1-17 and C.2.2.1-4).

c. No program is required to prevent or mitigate aging degradation due to erosion-corrosion (Tables C.2.1.1-10 and C.2.2.1-2).

RESPONSE TO RAI 3.1.1-7:

a. SNC has chosen, for some non-Class 1 components within the scope of license renewal, to credit inspections accomplished by other license renewal programs, such as TWSPI, for detection of aging effects requiring management, rather than the ISI program.

b. Table C.2.2.1-1 applies to corrosion only (not flow-accelerated corrosion or erosion corrosion), of non-Class I carbon steel components. Table C.2.2.1-3 applies to localized corrosion of non-Class I stainless steel components. Table C.2.2.1-4 applies to <u>cracking</u> of non-Class I stainless steel components due to corrosion. For the Non-Class I components described by the above tables, a review of Plant Hatch operating experience, generic industry information, and ASME Section XI inspection records did not reveal any significant aging concerns. However, SNC has conservatively postulated that localized corrosion and corrosion cracking could occur in the absence of chemistry controls, and that an appropriate inspection program is warranted.

   Due to the environmental controls provided by reactor water chemistry controls, and lack of degradation indicated by operating experience, only minimal corrosion and corrosion rates are expected. Thus, SNC has concluded that a one-time inspection of these components is adequate.

   If no significant degradation is found during the one-time inspection, the postulated aging effects will be considered adequately managed for the material/environment combination under consideration. If the results of the one time inspection indicate that significant corrosion processes are occurring, or if reactor water chemistry controls change such that increased corrosion is expected, the need for additional inspections and follow up examinations will be determined based on evaluation of inspection results.

   Table C.2.1.1-17 applies to cracking of cast austenitic stainless steel castings due to SCC. A review of generic industry information, Plant Hatch operating experience, and textbook information, indicates that SCC of cast austenitic stainless steels is very unlikely in the reactor water environment due to the presence of significant quantities of ferrite. Although SNC has conservatively postulated that corrosion cracking of these castings could occur, the potential is so low in the reactor water environment, when compared to other more susceptible locations, that specific inspections to detect this aging mechanism are not required. Therefore, control of environmental conditions via reactor water chemistry control alone is concluded to be adequate to manage corrosion cracking of these castings.

c. As stated in Tables C.2.1.1-10 and C.2.2.1-2, aging management programs designed to detect the effects of aging prior to loss of component function are utilized to manage FAC and erosion corrosion in the reactor water environment. See the response to RAI-3.1.1-3 for additional information.

RAI 3.1.1-8:

In Table 2.3.1-1 of the reactor assembly system (B11), the following components: access hole covers (nickel-based alloy), core delta P/SLC line (stainless steel), core support plate (stainless steel) and shroud tie rods (stainless steel) are listed as not requiring aging management. Provide the bases for such determinations.

RESPONSE TO RAI 3.1.1-8:

See the response to RAI 2.3.2-RA-2. For core delta P/SLC, also see the response to RAI 2.3.3-SCLS-2. SNC responded to these RAIs by letter dated August 29, 2000.

RAI 3.1.1-9:

The U.S. Nuclear Regulatory Commission (NRC) issued a safety evaluation report (SER), dated April 27, 1999, in which the staff found the BWRVIP-27 report, "BWR Vessel and Internals Project, BWR Standby Liquid Control System / Core Plate ΔP Inspection and Flaw Evaluation Guidelines," dated April 1997, acceptable for the current operating period of BWRs. According to Section 2.1 of the BWRVIP-27 report, industry experience has identified IGSCC as a potential aging effect for the ΔP/SLC vessel penetration/nozzle and safe-ends. Section C.2.2.4, of the LRA, does not identify aging due to IGSCC as an applicable aging effect. Identify all components potentially affected by IGSCC and describe how the aging effects due to IGSCC are managed during the period of extended operation.

RESPONSE TO RAI 3.1.1-9:

BWRVIP-27 addresses the piping inside the reactor vessel and the nozzle, or penetration, of the vessel. It does not address, and therefore should not be applied to, the non-Class 1 piping discussed in LRA Section C.2.2.4. Section C.2.2.4 addresses only that portion of the SLC system subjected to borated water under normal conditions, and does not include piping inside the vessel or vessel penetrations. AMRs for IGSCC susceptible vessel and vessel internals components are covered in LRA Table 3.2.1-1, and Sections C.2.1.1.1 and C.2.1.1.2.

RAI 3.1.1-10:

The staff notes that "safe ends" are listed as a component requiring AMR in Table 2.3.1-1 for the reactor assembly system (B11). Safe ends are usually connected to nozzles with dissimilar metal welds to accommodate the configuration changes between nozzles and piping. In which commodity group will the carbon steel "safe ends" with stainless steel or Alloy 182 connecting welds be assigned to for AMR. Provide a discussion regarding how the components with dissimilar metal welds will be adequately managed for aging effects in the existing commodity groups.

RESPONSE TO RAI 3.1.1-10:

The safe ends were listed as a separate component for completeness. The low-alloy steel and carbon steel safe-ends are covered by BWRVIP-74, as noted in LRA Section C.2.1.1.1.

Dissimilar metal piping welds (including nozzle-to-safe-end welds) NPS 4 and larger, for BWRs, are covered by the NRC required GL 88-01 inspections. These welds are included in the stainless steel piping commodity group, Section C.2.1.1.4, and the AMPs are reactor water chemistry control and the ISI program, which includes examinations required by GL 88-01. Dissimilar metal welds joining components smaller than NPS 4 are covered in the commodity group for the components they connect, and the AMPs are reactor water chemistry control and the ISI program (see LRA Section C.2.1.1.4).

RAI 3.1.1-11:

In Table 3.2.1-1 of the LRA, thermal sleeves are listed as a component requiring AMR. Thermal sleeves, in most cases, are not accessible for inspection and the outside diameter (OD) surface is exposed to a stagnant fluid environment. Therefore, discuss how the AMPs referenced in Table 3.2.1-1 of the LRA effectively mitigate such conditions, to ensure the structural integrity of the thermal sleeves, during the extended licensing period.

RESPONSE TO RAI 3.1.1-11:

The thermal sleeves were listed for completeness, and should not have been listed as a separate component. They are considered part of the nozzles that connect to the reactor vessel. Thus, the AMP that assures the integrity of the nozzles also assures the integrity of the thermal sleeves.

RAI 3.1.1-12:

Provide additional information regarding your operating experience pertaining to water chemistry transients due to resin intrusion, condensate leakage or other causes. Describe the bounding water chemistry transients in the last five years and the corrective/recovery actions taken to minimize the aging degradation of the affected components as well as to prevent recurrence.

RESPONSE TO RAI 3.1.1-12:

Water chemistry transient history was considered in the AMR for the commodity groups exposed to the reactor water environment. Review of chemistry records revealed that the EPRI Action Level 3 criteria were not exceeded at any time during the 5 years considered.

Minor water chemistry excursions were noted. For example, two isolated instances were identified. One was the result of a resin intrusion on Unit 1, and the other was due to the Unit 2 reactor water cleanup system being unavailable for a short time. Neither of these transients had a long-term aging impact.

A Unit 1 resin intrusion in the mid-1990s resulted in high sulfate concentrations for a short period of time. This incident occurred during reactor pressure vessel heat-up prior to power operation. Once the intrusion was identified, the source of resin was isolated and sulfates were returned to normal levels.

A Unit 2 reactor water cleanup system outage in 1999 resulted in chloride and sulfate levels within the reactor coolant system exceeding the EPRI Action Level 1 values for a short period. Following the restoration of the reactor water cleanup system, chloride and sulfate concentrations returned to normal levels.

AMRs concluded that these isolated, short-term transients had no significant impact on reactor vessel and reactor coolant system components. In addition, these transients had no impact on the acceptability of reactor water chemistry control as an effective aging management tool for the renewal term.

CLOSED COOLING WATER CHEMISTRY CONTROL

RAI 3.1.2-1:

The applicant states that the closed cooling water chemistry control is designed to mitigate age-related degradation by maintaining closed cooling water chemistry in accordance with EPRI guidelines. Discuss how monitoring the parameters chosen will mitigate the loss of material and cracking.

RESPONSE TO RAI 3.1.2-1:

Parameters monitored by CCW chemistry are discussed in Appendix B, Section 1.2.

The parameters monitored are based on the recommendations of EPRI TR- TR-107396, "Closed Cooling Water Chemistry Guideline." This document contains significant information regarding the potential effects of chemical species and microbe populations on CCW system corrosion and appropriate methodologies for chemical additions to CCW systems.

Corrosion cracking is not considered an aging effect requiring management for CCW system components in the scope of license renewal. The normal operating temperatures in the in-scope portions of the reactor building closed cooling water and primary containment chilled water systems are below the 140 °F threshold for corrosion cracking presented in the Plant Hatch LRA, Section C.1.2.2.2.

RAI 3.1.2-2:

In Section C.2.2.5 of the LRA, the applicant states that the closed cooling water chemistry control has become very complex over the years. The applicant further states that the program has grown to include 11 systems and 14 different analyses (plus coupons on RBCCW). The applicant notes that pH is monitored, corrosion coupons are used, and levels of detrimental impurities and microbiological impurities are monitored and trended. Provide a comprehensive list of the specific chemistry control parameters for the in-scope piping and components that are inspected or monitored.

RESPONSE TO RAI 3.1.2-2:

See Appendix B, Section 1.2.

RAI 3.1.2-3:

Discuss the bases for the techniques used to measure the parameters discussed in RAI 3.1.2-2 (e.g., EPRI guidelines, and ASTM procedures).

RESPONSE TO RAI 3.1.2-3:

As stated in Section A.1.2 of the Plant Hatch LRA, CCW chemistry control is based on the general recommendations of EPRI TR-107396, "Closed Cooling Water Chemistry Guideline." Additional detail regarding the standards utilized to accomplish CCW chemistry monitoring and adjustments are contained in applicable chemistry procedures, which are available on site for review.

RAI 3.1.2-4:

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 intervals. The applicant did not state the frequency of closed cooling water sampling in Appendix A, Section 1.2.2, of the LRA, other than to state that the "sampling, operational guidelines, type of treatment, and frequency of analysis are determined by the prevailing fluid conditions." State the frequency of sampling. If the sampling is not as frequent as recommended by the most recent EPRI closed cooling water chemistry guidelines, discuss why the sampling frequency is appropriate.

RESPONSE TO RAI 3.1.2-4:

See Appendix B, Section 1.2 for sampling frequencies. EPRI TR-107396, "Closed Cooling Water Chemistry Guideline" does not recommend applicable sample frequencies; only a methodology for establishing plant specific sample frequencies. At Plant Hatch, sample frequencies are adequate to detect significant changes in CCW composition prior to significant degradation of components. These frequencies are based on professional judgement and plant operating experience with CCW chemistry control.

RAI 3.1.2-5:

Monitoring and trending provide important information about how a system is performing relative to acceptance criteria. Proactive monitoring and understanding of trending behavior may allow corrective actions to be taken prior to exceeding acceptance criteria. Monitoring and trending of water chemistry parameters are also consistent with EPRI guidelines. The applicant stated in Appendix A, Section 1.2.1 that "[d]ata are reviewed, and trend analysis is performed." Provide the staff with a discussion of how the closed cooling water chemistry parameters are monitored and trended over time.

Also, the applicant states in Table C.2.2.5-1 of the LRA, that monitoring and trending is not necessary due to chemistry controls. In C.2.2.5.1, under the "Closed Cooling Water Chemistry Control" description, the applicant states that "levels of detrimental impurities and microbiological organisms are monitored and trended." Resolve this apparent inconsistency.

RESPONSE TO RAI 3.1.2-5:

Values obtained for the control parameters (i.e. acceptance criteria) identified in Appendix B, Section 1.2, are trended such as increases in chlorides or consumption of corrosion inhibitors. Identification of adverse trends provides for early diagnosis of, and response to, chemistry transients, thereby reducing the effects of those transients on system components. Chemistry transients exceeding procedurally established acceptance criteria are resolved in accordance with the Plant Hatch corrective actions program.

SNC evaluated "monitoring and trending" in Table C.2.2.5-1 as regards detection of aging effects via component inspections, not as regarding chemical parameters monitored by CCW chemistry control. As described in LRA Appendix A, Section A.1.2, and the Appendix B CCW chemistry control program description, monitoring and trending are important aspects of CCW chemistry control.

RAI 3.1.2-6:

Acceptance criteria is a necessary element to any AMP. The applicant did not provide the acceptance criteria for this program other than to state in Section A.1.2.3 that the ". . . framework for CCW chemistry control at the Hatch plant is based upon the guidance provided in the EPRI closed cooling water chemistry guidelines. Acceptance criteria contained therein are reflected in plant procedures." Provide the staff with the acceptance criteria for each parameter monitored. If the acceptance criteria is not as conservative as the most recent EPRI closed cooling water chemistry guidelines, provide the basis for the acceptability of the acceptance criteria.

Also, the applicant states in C.2.2.5 of the LRA, that the acceptance criteria are tied to loss of material rather than chemistry controls. The applicant states in Section A.1.2 that the acceptance criteria for CCW chemistry is in plant procedures. Resolve this apparent inconsistency.

RESPONSE TO RAI 3.1.2-6:

SNC has not taken any specific exceptions to the EPRI closed cooling water chemistry guidelines as regards acceptance criteria for the current CCW chemistry control methodology employed at Plant Hatch. These acceptance criteria are presented in Appendix B, Section 1.2.

Having appropriate acceptance criteria is an important aspect of chemistry control. The intent of line item 5 in tables C.2.2.5-1, C.2.2.5-2, and C.2.2.5-3 of the Plant Hatch LRA was to indicate that control of appropriate chemical parameters has been proven to reduce corrosion in closed cooling water systems (see the response to RAI 3.1.2-1).

RAI 3.1.2-7:

Operating experience provides the staff additional information about the acceptability of an AMP. The application stated in Section C.2.2.5, of the LRA, that "[s]ignificant changes in the sampling and analysis program have been made, based on internally identified deficiencies." The application further states that "[t]he closed cooling water chemistry program has extensive operating history demonstrating quality improvements made based on past problems. The Hatch chemistry program descriptions contain a discussion of this history." The staff has not been able to identify the location of the Hatch chemistry program in the application. Discuss prior chemistry control problems, recent chemistry excursions, and typical responses to such events. Relate the operating experience discussed generically in the relevant commodity groups (e.g., C.2.2.5.1, C.2.2.5.2, and C.2.2.5.3) to the closed cooling water chemistry control program.

RESPONSE TO RAI 3.1.2-7:

CCW chemistry at Plant Hatch has evolved to its current status as a result of increased industry research, operating experience, and specific issues associated with chemical additions and testing methods. What follows is a brief summary of the current Plant Hatch philosophy toward CCW system chemistry.

Currently, Plant Hatch treats CCW systems with nitrite/molybdate and TTA corrosion inhibitors. At times, in the past, only molybdates were utilized, since nitrite additions were contributing to nitrite consuming bacteria population growth. However, a molybdates-only treatment consumed dissolved oxygen in the system and left the carbon steel components vulnerable to corrosion, since the molybdates-only treatment did not promote an adherent oxide layer at low dissolved oxygen levels. This resulted in increased corrosion rates. Plant Hatch returned nitrites to the treatment system. This program change effectively resolved the corrosion issues, but significantly increased nitrite consuming bacteria activity.

In response to higher nitrite consuming bacteria populations, new biocides were added. Although the addition of new biocides that had been proven more effective against nitrite consuming bacteria brought nitrite consuming bacteria activity under control, decomposition of the new biocides increased chloride concentrations in the system. Eventually, chloride concentrations exceeded the EPRI-based recommendations. Subsequently, a bleed and makeup process using demineralized water was utilized to reduce chloride concentrations.

Currently, both nitrites and molybdates are added for corrosion control. Isothiazolone and Glutaraldehyde are added to control microbe populations. Isothiazolone is the primary contributor of chlorides in the systems. Therefore, Isothiazolone is used only when nitrite consuming bacteria populations are high. Finally, if elevated chloride levels occur, system bleed and makeup with demineralized water is used to lower the concentrations of impurities.

Corrosion coupon monitoring has been provided in the reactor building CCW system in order to verify the continued effectiveness of closed cooling water chemistry in minimizing corrosion rates. At this time, corrosion coupon data is well within the limits recommended by industry standards.

DIESEL FUEL OIL TESTING

RAI 3.1.3-1:

The diesel fuel oil testing program includes activities to mitigate the loss of material from diesel fuel oil storage and transfer components that could result from intrusion of water or other contaminants. The LRA states that the fire pump fuel oil storage tank and the emergency diesel generator fuel oil storage and day tanks are regularly checked for water and other contaminants in accordance with the Fire Hazards Analysis (FHA) and TS, respectively. Accumulated water is removed and fuel oil chemistry is adjusted when needed. Although these activities will result in managing aging effects, some loss of material may be expected. Indicate how the loss of material, which could potentially lead to leakage, will be detected during the period of extended operation.

RESPONSE TO RAI 3.1.3-1:

Routine removal of water from the tanks eliminates the necessary environment for corrosion in the fuel oil system. The water content in the oil is not sufficient to cause significant corrosion that might result in leakage during the extended period of operation. Operating experience indicates no failure of the fuel oil components due to loss of material. Therefore, managing fuel oil quality is sufficient to provide adequate aging management of fuel oil components.

RAI 3.1.3-2:

Explain why in Section C.2.3.2, of the LRA, flow blockage due to sediment buildup in the copper tubing of the supply lines to the fire protection pump diesel engine, was not identified as an aging effect, when in Section C.1.2.5.3, it is specified as an aging effect for the systems exposed to fuel oil.

RESPONSE TO RAI 3.1.3-2:

LRA Section C.1.2.5.3 incorrectly states that flow blockage due to sediment buildup is applicable for copper tubing supply lines to the fire protection pump diesel engine.

RAI 3.1.3-3:

In Section A.1.3.1, of the LRA, the applicant states that the total particulate concentration in diesel fuel oil is within acceptable limits. Specify those "acceptable limits."

RESPONSE TO RAI 3.1.3-3:

As noted in LRA Section A.1.3.3, the Plant Hatch Technical Specifications requires that stored fuel oil be maintained with a total particulate concentration less than 10 mg/liter. See Section 5.5.9(b) of the Unit 1 and Unit 2 Technical Specifications.

RAI 3.1.3-4:

In Section A.1.3.3, of the LRA, several documents containing acceptance criteria are referenced, but a list of the specific criteria was not provided. List all the acceptance criteria which are specifically applicable to this AMP.

RESPONSE TO RAI 3.1.3-4:

Acceptance criteria for diesel fuel oil are presented in Appendix B, Section 1.3.

PSW AND RHRSW CHEMISTRY CONTROL

RAI 3.1.4-1:

In Section A.1.4 of the LRA, the applicant states that the plant service water and residual heat removal service water chemistry control program is designed to mitigate age-related degradation in system piping and components by controlling water composition. The applicant states that the chemical additions are intended to manage MIC and microorganism intrusion. Are the other aging effects listed (e.g., loss of material due to crevice corrosion, pitting, etc.) managed by chemical additions or analysis? Discuss how monitoring the parameters chosen mitigates loss of material and cracking.

RESPONSE TO RAI 3.1.4-1:

Microbiological organisms that adhere to metal surfaces can disrupt the metal's protective oxide layer, produce corrosive substances, and trap solids that cause loss of material via underdeposit corrosion. Therefore, reduction of biofouling within service water systems serves to mitigate loss of material due to corrosion. Cracking results from thermal fatigue and is managed by TLAA.

Normally, each unit's PSW system is chlorinated/brominated separately five times a week, with a resultant FAO of at least 0.2 ppm as measured at the PSW system discharge to the circulating water flume. FAO is monitored during each event. The above biocide treatment reduces biofouling, and thereby reduces the loss of material caused by biofouling.

One section of PSW piping in the diesel generator building is protected with a shield pipe. Aging effects on the internal surface of the PSW pipe are managed by the PSW and RHRSW chemistry control program and the PSW and RHRSW inspection program. However, the external surface of the pipe is not readily accessible for aging management due to the shield pipe. The external surface is subject to loss of material due to general corrosion. Therefore, an inspection of the external surface of this section of pipe will be performed to assess the material condition of the pipe and inspection results will be factored into the AMP as appropriate.

RAI 3.1.4-2:

In Section A.1.4 of the LRA, the applicant states that the service water is treated with sodium hypochlorite and sodium bromide. In section C.2.2.6.1, the applicant states that these additions are to minimize microbiologically influenced corrosion and macroorganism intrusion within service water systems. The applicant also states that discharged measurable chlorine, free available oxidant, and total residual oxidant levels are governed by the Hatch National Pollutant Discharge Elimination System (NPDES) permit. Clarify that the sole chemistry control parameters for the piping and components that are inspected or monitored are discharged measurable chlorine, free available oxidant, and total residual oxidant levels.

RESPONSE TO RAI 3.1.4-2:

During PSW system chlorination and/or bromination, FAO concentration is periodically monitored and maintained within a specified range at the PSW system discharge to the circulating water flume. This measurement assures that sufficient oxidizing biocides are added to meet the system oxidant demand, and results in an effective residual FAO concentration. In addition, this monitoring is used to assure that the biocide addition program is operated consistent with the requirements and limitations of the Plant Hatch NPDES permit.

The NPDES permit requires that Plant Hatch monitor the final plant effluent to the Altamaha River for residual oxidant on a weekly basis and report the results quarterly.

RAI 3.1.4-3:

Discuss the bases for the techniques used to measure the parameters chosen for inspection and monitoring (e.g., EPRI guidelines, ASTM procedures, etc.).

RESPONSE TO RAI 3.1.4-3:

Specific information regarding sampling methods and analysis techniques are contained in site implementing procedures. Sampling methods and techniques are based on appropriate industry guidelines and Plant Hatch operating experience.

RAI 3.1.4-4:

The plant service water and RHR service water chemistry control program is intended to mitigate aging in system piping and components by controlling fluid composition through treatment with sodium hypochlorite and sodium bromide. The description of this program is provided in A.1.4 of the application. Discuss the criteria used to determine the duration of the chemical treatment and the criteria used to adjust the frequency of treatment.

RESPONSE TO RAI 3.1.4-4:

The duration and frequency of PSW chlorination and/or bromination is intended to meet the requirements of Generic Letter 89-13 with regard to control of biofouling in service water systems. These activities are based on appropriate industry guidance, vendor recommendations, Plant Hatch operating experience, and plant specific program commitments made regarding NPDES requirements.

RAI 3.1.4-5:

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 applicant included a section titled "Sample Size and Frequency" in Section A.1.4, of the LRA. Contrary to the title of the section, there is no discussion of sample sizes or how often the service water is sampled. Instead, there is a discussion of how the water is treated (with chlorination and bromination) and the duration of treatment. Provide details on how the samples, sample size and sampling frequency are determined, and how this sampling program mitigates the aging effects listed.

RESPONSE TO RAI 3.1.4-5:

PSW system effluent is sampled for FAO during each chlorination and/or bromination addition period. This sampling is intended to assure that the chemical additions are sufficient to meet the PSW system chlorine demand and provide a residual FAO concentration that results in adequate control of biological organisms in the PSW system. In addition, this monitoring assures that the biocide addition program is operated consistent with the requirements and limitations of the Plant Hatch NPDES permit.

In accordance with the Plant Hatch NPDES permit, Plant Hatch monitors the final plant effluent to the Altamaha River for residual oxidant on a weekly basis and reports the results quarterly.

See the Appendix B program description for PSW and RHRSW chemical control for additional information.

RAI 3.1.4-6:

Monitoring and trending provide important information about how a system is performing relative to acceptance criteria. Proactive monitoring and understanding of trending behavior may allow corrective actions to be taken prior to exceeding acceptance criteria. The only discussion provided on monitoring and trending is in terms of loss of material from inspections, not in terms of water chemistry parameters. Discuss how the [*plant service water*] chemistry parameters are monitored and trended over time.

RESPONSE TO RAI 3.1.4-6:

Monitoring requirements related to PSW system chlorination and/or bromination were presented in response to RAI 3.1.4-5. No trending of FAO/free available chlorine or residual oxidant is performed. The sole intent of PSW effluent sampling is to assure that FAO/free available chlorine values are maintained in a range adequate to provide effective biofouling control, while assuring that the program is operated consistent with the requirements and limitations of the Plant Hatch NPDES permit.

RAI 3.1.4-7:

Acceptance criteria are a necessary element to any AMP. The applicant states in Section A.1.4.3, of the LRA, that the acceptance criteria provided for this program are tied to the National Pollutant Discharge Elimination System (NPDES), rather than to managing aging effects. What are the chemistry acceptance criteria?

RESPONSE TO RAI 3.1.4-7:

See Appendix B, Section 1.4, for the discussion of PSW and RHRSW chemistry control acceptance criteria.

RAI 3.1.4-8:

Operating experience provides the staff additional information about the acceptability of an AMP. The application discusses the applicant's response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." Discuss chemistry control problems, recent chemistry excursions, and typical responses to such events since the program improvements cited in the application's review of operating experience. Relate the operating experience discussed generically in the relevant commodity groups (e.g., C.2.2.6.1, C.2.2.6.2, and C.2.2.6.3) to the plant service water and RHR service water chemistry control program.

RESPONSE TO RAI 3.1.4-8:

See Appendix B, Section 1.4, for the discussion of Plant Hatch operating experience related to PSW and RHRSW chemistry control.

FUEL POOL CHEMISTRY CONTROL

RAI 3.1.5-1:

Several other systems with aluminum components are listed as part of the commodity group for aluminum. These systems include the reactor building, tornado relief vents, yard structures, and control building. The loss of material aging effect and its corresponding AMP of fuel pool chemistry control refers only to aluminum components exposed to the spent fuel pool demineralized water. Clarify how the aging effects of aluminum components in the reactor building, tornado relief vents, yard structures, and control building are managed by the fuel pool chemistry control activities.

RESPONSE TO RAI 3.1.5-1:

The aluminum components in the reactor building, the tornado relief vents, yard structures, and control building are exposed to air inside structures, or to the outside environments. For these components, it was determined that there were no aging effects requiring management. These items are found in LRA Tables 2.3.4-2, 2.4.4-1, 2.4.10-1, 2.3.4-14, 2.4.5-1, and 2.4.13-1.

RAI 3.1.5-2:

Fuel pool chemistry control is designed to mitigate and prevent age-related degradation by controlling fluid purity and composition. The application further states that the program accomplishes timely monitoring and goal setting for degradation. The staff finds that the control of impurities in the fuel pool demineralized water can mitigate and prevent age-related degradation. Clarify what specific actions are taken to manage the loss of material due to component exposure to the spent fuel pool demineralized water.

RESPONSE TO RAI 3.1.5-2:

See Appendix B, Section 1.5. Also, see the responses to RAIs 3.1.5-3 and 3.1.5-4. Based on the information presented in the referenced RAI responses and Appendix B, the fuel pool chemistry program is adequate to mitigate the aging effects such that there would not be a loss of intended function in the renewal term.

RAI 3.1.5-3:

The application states that detection of aging effects is not required due to chemistry controls. However, chemical impurities in the fuel pool water may be indicative of a loss of material or may contribute to the loss of material. Clarify how the loss of material aging effect is detected and/or controlled.

RESPONSE TO RAI 3.1.5-3:

AMRs performed by SNC conclude that no detection of aging effects is required for adequate aging management of the components subjected to a spent fuel pool environment. This conclusion is based on the non-aggressive nature of the demineralized water environment in the spent fuel pool, and the inherent corrosion resistance of the stainless steel and aluminum alloys used in the spent fuel pool. Thus, a significant loss of material is prevented by spent fuel pool chemistry controls such that detection of the aging effect is not required. A review of Plant Hatch operating experience supports this conclusion, in that no instances of corrosion were identified.

For information regarding the environmental controls provided by spent fuel chemistry control, see Appendix B, Section 1.5. Also, see the response to RAI 3.1.5-4.

RAI 3.1.5-4:

The application states that monitoring and trending and parameters inspected or monitored are not required due to chemistry controls. However, the fuel pool chemistry control activities imply that actions are taken to prevent exceeding chemistry parameters. In addition, chemical impurities in the fuel pool water may be indicative of a loss of material or may contribute to the loss of material. Through the monitoring and trending of chemistry parameters, actions to control or detect the loss of material is achieved. In addition, the statement that monitoring and trending is not required due to chemistry controls contradicts Section A.1.5.2 of the LRA; this section states that fuel pool water is sampled regularly for conductivity, pH, chlorides and sulfates, filterable solids and total organic carbons. Clarify what chemical parameters are inspected or monitored in the fuel pool chemistry control activities and how the parameters are monitored and trended to detect and control the loss of material exposed to the spent fuel pool water.

RESPONSE TO RAI 3.1.5-4:

Spent fuel pool chemistry parameters are maintained in accordance with the parameters set forth in Appendix B of EPRI TR-105315, "BWR Water Chemistry Guidelines." See Appendix B, Section 1.5 of these RAI responses, for the chemistry parameters and sample frequencies.

The statement in the LRA that monitoring and trending is not required due to chemistry controls was intended to mean that monitoring or trending of the aging effect (loss of material) is not required because chemistry controls mitigate the effect such that loss of an intended function due to loss of material is not expected during the renewal term.

RAI 3.1.5-5:

The application states that detailed acceptance criteria is provided in the fuel pool chemistry control activities. Specify the acceptance criteria and the basis for such criteria.

RESPONSE TO RAI 3.1.5-5:

See Appendix B, Section 1.5.

RAI 3.1.5-6 (Revised 9/25/2000):

The application states that detailed acceptance criteria is provided in the fuel pool chemistry control activities. The staff requests the applicant to specify the acceptance criteria and the basis for such criteria.

RESPONSE TO RAI 3.1.5-6:

See Appendix B, Section 1.5.

DEMINERALIZED WATER AND CONDENSATE STORAGE TANK CHEMISTRY CONTROL

RAI 3.1.6-1:

With respect to the demineralized water and condensate storage tank chemistry control AMP described in Section A.1.6 of the LRA, provide the following information:

a. The program refers to 'contaminants' as monitored parameters but does not identify them (e.g., sodium chloride). Identify the contaminants referred to in the program description. In addition, discuss what, if any, potential impact these contaminants could have on the aging effects specified in Section C.2.2.4, as well as the structural integrity of the phenolic resin liner mentioned in Section C.2.2.4.1. If applicable, describe how the aging effects, due to the presence of each contaminant, are managed during the period of extended operation.

b. The program does not clearly describe the activities for prevention and mitigation of the aging effects. For example, the program states that "the demineralized water storage tank influent and effluent are monitored." Provide details on how the samples, sample size and sampling frequency are determined. In addition, what methods are employed to quantitatively and qualitatively analyze the results? Provide examples of the types of chemical modifications used, specifically, for a borated water environment. The program also lists the monitoring parameters (e.g., conductivity, pH, silica, chloride, sulfate and total organic carbon). Discuss the allowable values and/or ranges for each parameter as it applies to the borated water environment presented in Section C.2.2.4 of the LRA. Address the potential impact each parameter may have on the aging effects specified in Section C.2.2.4 of the LRA and describe how the aging effects due to a non-allowable monitoring parameter is managed during the period of extended operation.

c. Describe the program using the relevant ten elements for an AMP from the draft standard review plan, in sufficient detail, to allow the staff to evaluate the program's adequacy.

RESPONSE TO RAI 3.1.6-1:

Demineralized water and CST chemistry control is based on the recommendations of EPRI TR-103515, Rev. 2, "BWR Water Chemistry Guidelines." The CST and DWST chemistry parameters are maintained in accordance with the parameters set forth in that document. It provides detailed information regarding the potential effects of chemical species on corrosion rates and corrosion mechanisms, and is based on a large body of industry data and analysis regarding corrosion processes. See Appendix B, Section 1.6 of these RAI responses, for the chemistry parameters and sample frequencies.

The SLC storage tank contains a solution of sodium pentaborate in demineralized water. The concentration of sodium pentaborate is in accordance with Plant Hatch Technical Specification Figures 3.1.7-1 and 3.1.7-2. The normal sodium pentaborate concentration at Plant Hatch is approximately 10 to 15 percent by weight. Makeup to the SLC storage tank is demineralized water supplied from the DWST. Additionally, the only other source of influent or effluent is the SLC system itself. Therefore, chemistry control of the DWST provides reasonable assurance that unacceptable levels of detrimental impurities are not introduced into the SLC storage tank or the SLC system.

The addition of sodium pentaborate, while increasing conductivity, does not provide a source of detrimental impurities such as chlorides or sulfates which could attack the passive chromium oxide layer normally found on stainless steel surfaces. Furthermore, sodium pentaborate solutions do not provide for acidic conditions similar to those found in boric acid solutions. Typical pH values for sodium pentaborate solutions are in the neutral range under normal conditions. Therefore, neutral pH values, and the lack of detrimental impurities, reduce the likelihood of significant localized corrosion occurring in the stainless steel and lined components of the SLC system.

Recent Plant Hatch experience with SLC system components, as mentioned in Section C.2.2.4 of the Plant Hatch LRA, supports this rationale, since no significant corrosion was identified. Information concerning applicable aging effects in a borated water environment is presented in Section C.1.2.2.

SUPPRESSION POOL CHEMISTRY CONTROL

RAI 3.1.7-1:

The applicant stated in Section A.1.7 of the LRA, that the scope of the suppression pool chemistry control program includes components within the RHR system, core spray system, high pressure coolant injection system, reactor core isolation cooling system, and a portion of the safety relief valve tailpipes. The applicant stated that the program also includes the suppression chamber shell, vent header, deflectors and supports, downcomers and braces, and suppression chamber interior platform support. The staff cannot identify from the application the systems which contain the safety relief valve tailpipes, suppression chamber shell, vent header, deflectors and supports, downcomers and braces, and suppression chamber interior platform support. Provide this information.

RESPONSE TO RAI 3.1.7-1:

The SRV tailpipes support function B21-01 Pressure Control, and are listed as piping in LRA Table 2.3.1-2. The remainder of the items mentioned in the RAI are all steel components that support function T23-01 Torus/Drywell. SNC presented aging management of components subject to AMR by a "commodities approach." Thus, these steel components, being part of the drywell and torus, are addressed in LRA Table 2.4.3-1 variously as "Structural Steel", "Miscellaneous Steel", or "Vent Pipe, Vent Header, Downcomers." The AMR for these components is presented in LRA Section C.2.6.2.

RAI 3.1.7-2:

Based on the tables in Section 3.2 of the LRA and the commodity group discussions, the staff considers the nuclear boiler system, primary containment, and the primary containment purge and inerting system to be included within the scope of the suppression pool chemistry control program. However, the applicant did not identify these systems as being within scope of this program in Section A.1.7, of the LRA. Clarify the scope of the suppression pool chemistry control program to resolve this inconsistency.

RESPONSE TO RAI 3.1.7-2:

See Appendix B, Section 1.7, for discussion of the program scope.

RAI 3.1.7-3:

The applicant monitors conductivity, chlorides, sulfates, zinc, and total organic carbons as part of the suppression pool chemistry control program. Discuss why each of these parameters is monitored in terms of how monitoring these parameters mitigate loss of material and cracking.

RESPONSE TO RAI 3.1.7-3:

Suppression pool chemistry control is based on the recommendations of EPRI TR-103515, Rev. 2, "BWR Water Chemistry Guidelines." This document provides detailed information regarding the potential effects of chemical species on corrosion rates and corrosion mechanisms, and is based on a large body of industry data and analysis regarding corrosion processes.

See Appendix B, Section 1.7, for discussion of monitored parameters.

RAI 3.1.7-4:

The applicant monitors conductivity, chlorides, sulfates, zinc, and total organic carbons as part of the suppression pool chemistry control program. Discuss the techniques used to measure these parameters (e.g., EPRI BWR water chemistry guidelines, and ASTM procedures).

RESPONSE TO RAI 3.1.7-4:

As stated in LRA Section A.1.7, suppression pool chemistry control is based on the recommendations of EPRI TR-103515, Rev. 2, "BWR Water Chemistry Guidelines." See Appendix B, Section 1.7, for additional information.

RAI 3.1.7-5:

The applicant did not state the frequency of the suppression pool water sampling, other than to state that the "sample frequencies. . .are based upon the applicable portions of the EPRI guidelines or other updated industry guidance." State the frequency of sampling. If the sampling is not as frequent as recommended by the most recent EPRI BWR water chemistry guidelines, discuss why the sampling frequency is appropriate.

RESPONSE TO RAI 3.1.7-5:

See Appendix B, Section 1.7.

RAI 3.1.7-6:

Monitoring and trending provide important information about how a system is performing relative to acceptance criteria. Proactive monitoring and understanding of trending behavior may allow corrective actions to be taken prior to exceeding the acceptance criteria. Monitoring and trending of water chemistry parameters are also consistent with EPRI BWR Water Chemistry Guidelines. The application did not state that any monitoring and trending of the chemistry parameters discussed above takes place. Provide a discussion of how the suppression pool chemistry parameters are monitored and trended over time. If no monitoring and trending is conducted, discuss why this aspect of an AMP is not needed.

RESPONSE TO RAI 3.1.7-6:

See Appendix B, Section 1.7.

RAI 3.1.7-7:

Acceptance criteria are a necessary element to any AMP. The applicant did not provide the acceptance criteria for the suppression pool chemistry control program other than to state that the "acceptance criteria. . .are based upon EPRI guidelines or other updated industry guidance. . ." Provide the acceptance criteria for each parameter monitored. If the acceptance criteria are not as conservative as the most recent EPRI BWR water chemistry guidelines, provide the basis for the acceptability of the acceptance criteria.

RESPONSE TO RAI 3.1.7-7:

See Appendix B, Section 1.7.

RAI 3.1.7-8:

Operating experience provides additional information about the acceptability of an AMP. The application did not provide operating experience relative to the suppression pool chemistry control program. Discuss prior chemistry control problems, recent chemistry excursions, and typical responses to such events. Relate the operating experience discussed generically in the relevant commodity groups (e.g., C.2.2.3, C.2.6.2, and C.2.2.11) to the suppression pool chemistry control program. Finally, discuss your plant-specific experience with MIC and how your chemistry control program addresses the potential for MIC to occur.

RESPONSE TO RAI 3.1.7-8:

Suppression pool chemistry excursions have been rare. In the past five years, only minor excursions above the criteria specified in EPRI TR-103515, "BWR Water Chemistry Guidelines" have occurred. None of these excursions was determined to be significant. In addition, Plant Hatch has not identified any problems in the suppression pools due to microbiologically influenced corrosion within the past five years.

Also, see Appendix B, Section 1.7.

RAI 3.1.7-9:

Discuss how excessive sedimentation of coating materials (for example, as discussed in IN 88-82, "Torus Shells with Corrosion and Degradation Coatings in BWR Containments") affects the chemistry control test results. Discuss how your sampling techniques and/or test methods avoid potential contamination of the samples by excessive debris in the torus.

RESPONSE TO RAI 3.1.7-9:

Suppression pool samples are obtained under pressure at the discharge to the core spray jockey pumps. These pumps take suction from ECCS suction lines connected to the torus. All ECCS suction lines are located away from the bottom of the torus, and thereby prevent inclusion of excessive sediment. These lines also include suction strainers to prevent entrainment of debris. Finally, flow rates and associated pipeline velocities in the jockey pump systems are low under normal operating conditions, preventing the entrainment of fine sediment into chemistry samples. Therefore, excessive sediment and debris in the torus is unlikely to occur, and does not adversely affect suppression pool chemistry sampling.

For additional information regarding torus desludging and inspection, see the response to RAI 3.1.29-7.

RAI 3.1.7-10:

The results of various inspection programs may be directly relevant to the chemistry control program. Discuss how you incorporate the results of the torus submerged components inspection program, the galvanic susceptibility inspection program, the treated water systems piping inspections, the RHR heat exchanger testing and inspection program, and the inservice inspection (ISI) program into your suppression pool chemistry control program.

RESPONSE TO RAI 3.1.7-10:

Suppression pool water chemistry control is based on the guidance of EPRI TR-103515, "BWR Water Chemistry Guidelines." This guideline does not allow for chemical additions such as corrosion inhibitors or biocides, since the suppression pool is a potential source of makeup water to the reactor coolant system during transient and accident conditions. Additionally, no method currently exists to efficiently modify suppression pool chemistry during normal operation. Therefore, the results of torus inspections, while utilized to evaluate required corrective actions and additional inspection requirements would not be used to suggest modifications to the current chemistry regime.

CORRECTIVE ACTIONS PROGRAM

RAI 3.1.8-1:

Appendix A, "Final Safety Analysis Report Supplement," Section A.1.8, "Corrective Action Program" (CAP), provides a brief description of the CAP and states that the CAP applies to all systems, structures, and components within the scope of license renewal. The CAP is also described as part of the applicant's Quality Assurance Program as required by 10 CFR Part 50 Appendix B.

Section C.2 of Appendix C to the LRA provides an AMR summary for each unique structure, component, or commodity group at Hatch 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 a demonstration as to how the identified aging management programs manage aging effects requiring management using attribute tables. The attributes identified for each AMR appear to be consistent with those attributes described in Section A.1, "Aging Management Review - Generic," Table A.1-1, "Elements of an Aging Management Program for License Renewal," of the NRC's Draft Standard Review Plan for License Renewal (DSRP-LR). However, the Hatch LRA does not appear to provide a description of each of these attributes. Please provide a description of each of the 10 attributes identified within the AMR tables. This RAI 3.1.8-1.

RESPONSE TO RAI 3.1.8-1:

The description for each of the 10 attributes is the same as the description given in the draft SRP-LR.

RAI 3.1.8-2:

Section A.2, "Quality Assurance for Aging Management," of the DSRP-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.

Section C.2 of Appendix C provides an aging management summary for each unique structure, component, or commodity group at Hatch determined to require aging management during the period of extended operation. For the majority of these AMR's three attributes (Corrective Actions, Confirmation Process, and Administrative Controls) are specifically addressed by reference to the applicant's CAP. However, Appendix A, Section A.1.8, does not appear to provide a description of how the CAP program specifically addresses those three attributes for which credit is being sought. Therefore, the applicant is requested to provide a description of how the CAP program specifically addresses those three attributes for the aging management programs at Hatch during the period of extended operation.

RESPONSE TO RAI 3.1.8-2:

The Plant Hatch LRA used the label "Corrective Action Program" for a combination of plant activities that includes the plant's corrective action program and portions of the plant's 10 CFR 50 Appendix B quality assurance (QA) program. See Appendix B of these RAI responses for a description of how this program addresses the attributes credited.

INSERVICE INSPECTION PROGRAM

RAI 3.1.9-1:

Section A.1.9 of the LRA discusses the three types of visual examinations defined in ASME Section XI (IWA-2210) used by Hatch in conducting such exams. However, the submittal does not discuss the inspection requirements of BWRVIP-03, "BWR Reactor Pressure Vessel and Internals Examination Guidelines," which is given as a general reference. Since Hatch has committed to follow the BWRVIP program, which utilizes the standards listed in the BWRVIP-03 guidelines, discuss how the Hatch ISI applies these standards in performing inspections, especially of the BWR vessel and internal components referenced in Section A.1.15 and Tables C.2.1.1-1 and C.2.1.1-5 of the LRA.

RESPONSE TO RAI 3.1.9-1:

The LRA provided BWRVIP-related information based on discussion in a January 7, 2000 meeting between representatives of NRC (LR and EMCB branches) and BWRVIP. The LRA information was presented at a level of detail determined in that meeting to be appropriate for components covered by the BWRVIP program.

The BWRVIP-03 guidelines will be implemented for each component that requires the use of a BWRVIP I&E document as part of aging management. The visual examinations conducted to satisfy Code requirements will meet the ASME Section XI criteria.

RAI 3.1.9-2:

Section A.1.9.1 of the LRA states that "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 support." Confirm that the ISI program at Hatch will include non-Class 1 components. If not, provide the bases and justification for not taking credit for the ISI program in the AMR for non-Class 1 components, such as the components in the commodity groups C.2.2.1.1 and C.2.2.1.2 made of carbon steel and stainless steel, respectively.

RESPONSE TO RAI 3.1.9-2:

The Plant Hatch ISI program complies with 10 CFR 50.55a regarding the use of ASME Section XI for ISI. It includes the appropriate sampling of Classes 1, 2, 3 and MC as prescribed by the regulation.

SNC has chosen, for some non-Class 1 components within the scope of license renewal, to credit inspections accomplished by other license renewal programs, such as TWSPI, for detection of aging effects requiring management, rather than the ISI program. Aging effects for non-Class 1 carbon steel and stainless steel components that are the subject of this RAI are managed by the programs and activities identified in LRA Sections C.2.2.1.1 and C.2.2.1.2. Those sections present information to demonstrate that adequate aging management is provided for the subject components. Appendices A and B provides a summary description of each credited program.

RAI 3.1.9-3:

The staff notes that the referenced ISI program also includes augmented examinations that the applicant is committed to perform. The applicant identified two documents, GL-88-01, "NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) in BWR Austenitic Stainless Steel Piping," and NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking," for such examinations. The staff also notes that I&E Bulletin (IEB) 80-13, "Cracking in Core Spray Spargers," dated May 12, 1980, requires augmented examinations of core spray internal piping and spargers in operating BWRs. This document is not identified in the ISI program. Although the inspection guidelines in IEB 80-13 have recently been replaced by those in BWRVIP-18, "Core Spray Internals Inspection and Flaw Evaluation Guidelines," there should still be a reference to IEB 80-13 in the ISI program for the purpose of identifying the applicant's original commitment to perform such examinations.

RESPONSE TO RAI 3.1.9-3:

BWRVIP-18 replaces previous commitments to IEB 80-13. Past commitments are part of the plant's historical record.

RAI 3.1.9-4:

GL 88-01 provides guidelines for augmented inspections of the reactor coolant pressure boundary components that are susceptible to IGSCC. The scope of inspection covers all components made of stainless steel and nickel-based alloys (such as Alloy 600 and Alloy 182) with diameters equal to or larger than 4 inches, irrespective of Code classification, that are exposed to a service temperature above 200 °F. Discuss how this program is implemented and identify all the systems and components that are covered under this program. Provide justification for not taking inspection credit for this program in the AMR of non-Class I stainless steel components.

RESPONSE TO RAI 3.1.9-4:

See the response to RAI 3.2.3.2-7. Plant Hatch has performed, and will continue to perform, piping and safe end examinations in accordance with GL 88-01, or NRC approved alternatives such as BWRVIP-75. The NRC issued an SER for BWRVIP-75 on September 15, 2000. NRC is currently reviewing a request for technical alternative for SNC to use BWRVIP-75. The GL 88-01 examinations are part of the ISI program, as noted in Section A.1.9 of the LRA. The August 2000 GALL document is consistent with this position.

There is no non-Class1 piping subject to the GL 88-01 program that is part of the scope of license renewal. Thus, the AMR for non-Class 1 stainless steel does not credit GL 88-01.

RAI 3.1.9-5:

When a dissimilar metal weld is fabricated, the weld metal is different from the material of the components being joined. For example, in joining the carbon steel safe-end to the pressure vessel nozzle, usually Alloy 182 is used as a butter and weld metal. Furthermore, the staff notes that dissimilar metal welds are not considered as independent mechanical components in the tables in Section 3.2 of the LRA, which lists all the components for the mechanical systems. Since the referenced components are made of carbon steel, they would be classified into the carbon steel commodity group. Therefore, the applicant's review process might not have identified the applicable aging effects pertaining to the IGSCC of the dissimilar metal weld and the potential aging effect of galvanic corrosion due to the coupling of different metals. Address this potential deficiency.

RESPONSE TO RAI 3.1.9-5:

Dissimilar metal welds are used to join different metals, regardless of the material classification of the weld metal utilized. Where dissimilar metal welds occur, the management of aging effects is addressed by the commodity group containing the more limiting material (e.g. stainless or nickel based alloy weld material is evaluated in the applicable stainless steel commodity group in reactor coolant applications where IGSCC is a concern). Any potential galvanic couple is addressed by the commodity group containing the more active metal (in this case, the carbon steel commodity group).

Also, see the response to RAI 3.1.9-4. In piping subject to GL 88-01, these dissimilar welds are inspected in accordance with the requirements of GL 88-01. These GL 88-01 mandated examinations are conducted as part of the Plant Hatch ISI program discussed in Section A.1.9 of the Plant Hatch LRA.

For piping not subject to GL 88-01 (e.g. stainless pipe less than 4" or not containing reactor coolant at a temperature greater than 200 °F), the AMPs described in the LRA adequately address applicable aging effects associated with dissimilar metal welds.

RAI 3.1.9-6:

Provide a detailed description of the programs for augmented examinations that are committed to be performed. Specifically, examinations that are in addition to the ASME Code, Section XI, ISI requirements. Identify the system, components, and inspections for which credit is being taken in the AMP.

RESPONSE TO RAI 3.1.9-6:

The ISI program is described in LRA Section A.1.9.1. The augmented examinations performed in addition to the Section XI requirements are described in detail in the ISI Plan that implements the NRC reviewed and approved ISI Program. The ISI Plan is available for review at SNC offices or at Plant Hatch. The three augmented programs for which credit is taken to manage aging are the GL 88-01 program, the NUREG-0619 program, and the BWRVIP program. GL 88-01 applies to stainless steel piping NPS 4 and larger containing reactor coolant at a temperature of 200 °F or greater (see the response to RAI 3.1.9-4). NUREG-0619 applies to the feedwater nozzle inner radius and bore region. The BWRVIP program is described in LRA Section A.1.15.1. The components to which it applies are identified in Sections C.2.1.1.1 and C.2.1.1.2.

RAI 3.1.9-7:

Provide additional information regarding operating experience pertaining to water chemistry transients due to resin intrusion, condensate leakage, or other causes. Describe the bounding water chemistry transients that have occurred in the last five years and the corrective/recovery actions taken to minimize the aging degradation of the affected components as well as to prevent recurrence.

RESPONSE TO RAI 3.1.9-7:

See the response to RAI 3.1.1-12.

OVERHEAD CRANE AND REFUELING PLATFORM INSPECTIONS

RAI 3.1.10-1:

Loss of material has been identified as an aging effect requiring aging management for the overhead crane and refueling platform. In addition, cracking due to fatigue is a common concern, particularly at flame-cut holes in the rails. Provide clarification as to whether the Overhead Crane and Refueling Platform Inspections include the effects of fatigue on components such as the crane rails. Also, identify the components where flame cut holes exist and describe the specific inspection activities to manage fatigue cracks.

RESPONSE TO RAI 3.1.10-1:

The overhead crane and the refueling platform are active components. However, SNC evaluated the structural integrity of the crane and refueling platform. The crane rails were evaluated as part of the reactor building T29 boundary. Loss of material due to corrosion of the overhead crane and refueling platform rails is managed by the AMP for the reactor building, LRA Appendix C.2.6.3. The "Structural Steel" line item in Table 3.2.4-13 includes the overhead crane and refueling platform, and identifies loss of material due to corrosion as the only aging effect requiring management. LRA Appendix C.2.6.3 also addresses these components. Structural integrity components of the overhead reactor building crane and refueling platform are visually inspected for evidence of loss of material, as described in Appendix B, Section 1.10.

The carbon steel reactor building overhead traveling crane was designed and constructed to conform to the Crane Manufacturer's Association of America Specification No. 70. Holes in crane rails and associated bolted connections were specified to meet standard fabrication tolerances in accordance with the AISC Code of Standard Practice, and were required to be punched, subpunched, and reamed or drilled. In addition, SNC has conducted walkdowns of the crane structure. Based on those walkdowns, SNC concludes that there are no flame cut holes.

RAI 3.1.10-2:

Fatigue damage can occur in such sub-components as wire ropes, drums, sheaves, clips, bolts, and stops. In the wire ropes the effects of the fatigue damage are cracking and breaking of the individual strands that make up the rope. Fatigue damage can also result from cyclic bending and vibrational stresses of the wire ropes. Thermal fatigue resulting in wear and mechanical degradation/distortion is a concern for carbon steel components. Describe the inspection and maintenance programs to manage these aging effects.

RESPONSE TO RAI 3.1.10-2:

The reactor building overhead crane and the refueling platform are active components. However, SNC evaluated the structural integrity of the crane and refueling platform. The passive structural load bearing components including the crane girder, rails, and bolts were evaluated for aging management. The active moving sub-components including the wire rope, drums and other associated parts did not require aging management review. The AMR for the structural load bearing components determined that fatigue was not an aging effect requiring management. The AMR, including the reactor building overhead crane and the refueling platform only, identified loss of material due to corrosion as an aging effect requiring management. Structural integrity components of the overhead reactor building crane and refueling platform are visually inspected for evidence of loss of material, as described in Appendix B, Section 1.10.

RAI 3.1.10-3:

Indicate whether self-loosening of bolted connections, due to vibration, was considered as an aging effect and provide a technical justification if this aging effect was not considered.

RAI RESPONSE TO RAI 3.1.10-3:

See the response to RAI 3.6-9.

RAI 3.1.10-4:

Due to vibratory loading, the expansion and undercut anchors in concrete may loosen due to local degradation of the surrounding concrete. Provide a technical justification for not identifying loss of preload due to the effects of vibration on the concrete surrounding the expansion and undercut anchors.

RESPONSE TO RAI 3.1.10-4:

See the response to RAI 3.6-9.

RAI 3.1.10-5:

Table 3.2.4-2 of the LRA states that the Refueling Equipment Assembly [F15] contains aluminum rivets for structural support. What surface does the aluminum rivets contact? Is galvanic corrosion between the rivets and the structural steel an aging concern?

RESPONSE TO RAI 3.1.10-5:

The aluminum rivets are in contact with painted carbon steel. During the riveting process, it is possible that the aluminum rivet head could pierce the coating on the steel and contact the steel. However, galvanic corrosion 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.

RAI 3.1.10-6:

The overhead and refueling platform crane inspection program provides for the visual inspection and testing of the reactor overhead cranes and crane rail supports and refueling platform to assure the safe operation of the crane. The staff requests the applicant to provide operating experience relevant to the application of this aging management program. The discussion in C.2.6.3 of the license renewal application did not specifically discuss this program nor did it discuss the operating experience relative to either the crane or the refueling platform.

RESPONSE TO RAI 3.1.10-6:

See Appendix B, Section 1.10.

TORQUE ACTIVITIES

RAI 3.1.11-1:

Torque activities are intended to mitigate loss of preload through the use of proper torque techniques at Hatch. Plant procedures provide specific instructions for maximizing the effectiveness of torque activities. Torque activities are evaluated in Section 3.1.11 of the LRA. However, loss of preload can occur regardless of applying the correct torque. Discuss how this AMP can manage loss of preload.

RESPONSE TO RAI 3.1.11-1:

The torque activities mitigate the loss of preload such that there will not be a loss of intended function. See Appendix B, Section 3.1.11.

RAI 3.1.11-2:

In previous applications for license renewal, applicants limited the yield strength on bolts to less than 150 ksi or used operating experience to prevent stress corrosion cracking in the bolts. Indicate if the yield strength in the design specs for ASME SA-193, "Specification for Alloy-Steel and Stainless Steel Bolting Materials for High-Temperature Service," (Grade B7) is limited to less than 150 ksi to avoid the possibility of stress corrosion cracking.

RESPONSE TO RAI 3.1.11-2:

This response only addresses details regarding bolting at Plant Hatch. Information related to bases for information contained in the ASME SA-193 specification is not presented. The subject bolting material has a minimum yield strength of 105 ksi. The torque activities AMP limits the torque applied, such that the bolt stress remains significantly lower than the minimum yield strength. Therefore, SCC is not considered an aging effect requiring management for the specific bolting material at Plant Hatch.

RAI 3.1.11-3:

In the LRA, torque activities is identified as an AMP to manage loss of preload for bolts in many systems. However, bolts used in some structures do not appear to require torquing activities. Why are the torque activities not applied to the bolts in the primary containment, fuel storage, reactor building, turbine building, the intake structure, the yard structures, the emergency diesel generator (EDG) building, the main stack, and the control building? Are there any other systems, structures, or components where bolts are used and the torque activities are not applied?

RESPONSE TO RAI 3.1.11-3:

The torque activities AMP described in LRA Appendix A, and in Appendix B to these RAIs, is applied to mechanical systems and components. It was not intended to be applied to structural bolting because the structural joints are not susceptible to significant loss of preload due to self-loosening. Structural bolts and anchors are installed in accordance with design documents and Plant Hatch bolting and anchoring procedures during fabrication and erection. Joints in passive structures that are properly designed and torqued during installation will not experience significant loss of preload. Bolts that are subject to load reversals or vibratory loads are torqued sufficiently upon installation to minimize loss of preload. In some cases, they may be provided with double nuts or lock-washers to prevent relaxation of tension in the bolts. The torque activities AMP is not credited in the anchorage and erection of electrical component supports, raceway supports, piping and tubing supports, and HVAC duct supports, because bolt installation torque is considered acceptable to prevent loss of preload due to self-loosening.

RAI 3.1.11-4:

Are additional actions (e.g. ISI program, system walkdowns, system leak tests) required to manage the aging of bolted connections?

RESPONSE TO RAI 3.1.11-4:

Section 3.2 of the LRA provides the AMPs relied on to manage the aging effects for mechanical systems. The aging effects identified for bolted connections are loss of material and loss of preload. As stated in Appendix B, Section 1.11, torque activities account for any loss of preload that may occur in bolted connections. The protective coatings program manages loss of material. Furthermore, ISI is performed on Class 1 components. No additional actions are required to manage the aging of bolted connections.

RAI 3.1.11-5:

Provide specific examples of the operating experience associated with loss of preload for bolted joints where the torque activities were applied.

RESPONSE TO RAI 3.1.11-5:

The torque activities AMP is intended to mitigate loss of preload and correct it in a timely manner via the corrective action program when leakage is found. Plant operating experience, as described in Appendix B, Section 1.11, indicates that these actions have been performed at Plant Hatch without loss of intended function.

COMPONENT CYCLIC OR TRANSIENT LIMIT PROGRAM

RAI 3.1.12-1:

Section A.1.12.1 of the LRA states that "the program tracks reactor coolant pressure boundary (RCPB) cyclic and transient occurrences to ensure that the RCPB components and the torus remain within the ASME Section III fatigue limits." Provide a description of the methodology used by the Plant Hatch Component Cyclic or Transient Limit Program (CCTLP) to track RCPB cyclic and transient occurrences to ensure that RCPB components and the torus remain within the ASME Section III fatigue limits.

RESPONSE TO RAI 3.1.12-1:

The CCTLP for the RPV locations is fully described in Unit 1 FSAR, Section 4.2.5 and Unit 2 FSAR, Section 5.4.6.4. The process for performing Class 1 piping and torus evaluations is very similar. See Appendix B, Section 1.12, for the CCTLP. Additional detail is provided below on the methodology used to develop the formulas for Class 1 piping and the torus.

Class 1 piping:

For Class 1 piping, the methodology used to develop the fatigue monitoring formulas is the same as that used in the governing Class 1 stress reports. The methodology expresses the detailed fatigue calculation for each location in formula form, where the number of cycles is a variable input based on the number of events actually experienced by the piping location.

The fatigue formulas are based on an event-pairing method. The event pairing methodology emulates the fatigue calculation developed in the governing stress reports as follows. First, a formula representative of an "empty" fatigue calculation (or fatigue table) from the stress report is developed. Then, as transient events are counted, the fatigue table is filled in with the appropriate numbers of cycles, and fatigue usage is calculated. Thus, if all design basis events are experienced by the plant in a quantity equal to that assumed in the design basis, this process will reproduce the stress report fatigue usage. Using this process, formulas are generated for all selected locations from the governing stress reports. Transient definitions are also provided which define how the counted events fit into the fatigue formulas.

The event-pairing methodology produces conservative values of fatigue usage, since design basis transient severity is assumed (i.e., the formulas emulate the design basis stress report fatigue calculations).

The transient definitions used in the governing stress reports for the piping locations evaluated in these calculations generally follow the detailed transient definitions provided by the NSSS vendor, GE. Those definitions are provided on thermal cycle diagrams, which were reviewed, for both Plant Hatch units. This information provides a basis for some of the judgements used in establishing the transient definitions used in the formulas by duly considering the stress report transient pairing definitions.

Torus:

For the torus, CUF monitoring formulas were developed that are in compliance with the current design basis calculations used to document the fatigue usage factors reported in the Plant Hatch Units 1 and 2 PUARs for the Mark 1 Containment Long Term Program, unless specific conservatism was identified and removed with justification. An example of this conservatism might be the enveloping of all dynamic event cycles, and applying all those cycles to the highest stress condition. Where this resulted in an unrealistically high CUF, a more detailed evaluation of stresses and cycles was performed.

To determine the areas of the torus shell, torus vent system, and torus penetrations which were to be considered critical locations from a fatigue standpoint, the current fatigue calculations which covered these areas, and the PUAR were reviewed. These calculations defined the critical areas for each area of the torus in terms of fatigue. For example, for the Unit 2 torus, the following locations were chosen for evaluation by the current fatigue calculation:

- Column to torus shell connection
- Ring girder to torus shell connection
- Mitre joint between adjacent bays
- Saddle to torus shell connection
- Shell thickness transition

Of these five locations, the one demonstrated to have the highest CUF for 40 years was used to develop a monitoring formula.

SRV setpoint changes, power uprate, and extended power uprate documents were reviewed. The only effect on fatigue formulas was an 11% increase in loads for the vent header and vent system. Other than accident and earthquake loads, the only transient that significantly contributes to torus fatigue is SRV lifts. SRV lifts, to date, were counted by reviewing historical operating records. Using this collected data, the current CUF was calculated.

RAI 3.1.12-2:

To determine that the RCPB and torus remain within the Section III fatigue limit, the fatigue calculations require the use of the ASME fatigue curves to determine the cumulative usage factor (CUF). These fatigue curves have been shown to be affected by the reactor water environment, therefore, the program may underestimate the CUF. Provide the CCTLP methodology for considering the effects of the reactor water environment on the ASME Section III fatigue curves.

RESPONSE TO RAI 3.1.12-2:

See the response to RAI 4.2-2 for the RCPB portion of this question.

See the response to RAI 3.1.12-1 for how torus fatigue formulas were developed.

The CUF for the torus and torus penetrations is driven solely by dynamic loads (i.e., SRV discharge and earthquake loads). During these loading conditions, the fluid temperature in the torus is well below the 300°F temperature threshold set by PVRC for consideration of reactor water environmental effects. Therefore, reactor water environmental effects are not applicable during the dynamic loading conditions that drive the torus assembly CUF.

RAI 3.1.12-3:

The magnitude of the CUFs vary from location to location. Presumably, the CCTLP monitors the locations with the highest CUFs. For each unit, provide the limiting location and currently calculated fatigue CUF for the reactor pressure vessel (RPV) main closure studs, the RPV shell, the RPV recirculation inlet nozzles, and the RPV feedwater nozzles.

RESPONSE TO RAI 3.1.12-3:

Component	Limiting Location	Current CUF	Projected 60-year CUF
Unit 1 Main Closure	Studs	0.2968	0.4552
Unit 1 Vessel Shell	Joint between $5^3/_8$" & $6^3/_8$" shell	0.0267	0.0669
Unit 1 Recirculation Inlet Nozzle	Joint between thermal sleeve & nozzle (Loop A)	0.2968	0.4796
Unit 1 Feedwater Nozzle	Safe End	0.1229	0.1663
Unit 2 Main Closure	Studs	0.3956	0.8434
Unit 2 Vessel Shell	Adjacent to Vessel Flange	0.0271	0.0513
Unit 2 Recirculation Inlet Nozzle	Thermal sleeve	0.1615	0.2983
Unit 2 Feedwater Nozzle	Thermal Sleeve	0.1858	0.3643

RAI 3.1.12-4:

The magnitude of the CUFs vary from location to location. Presumably, the CCTLP monitors the locations with the highest CUFs. For each unit, provide the basis for establishing the limiting locations where fatigue CUFs are calculated.

RESPONSE TO RAI 3.1.12-4:

See Appendix B, Section 1.12.

The locations for the RPV are established in the CLB. See Unit 1 FSAR, Section 4.2.5 and Unit 2 FSAR, Section 5.4.6.4.

For the Class 1 piping formulas, see the response to RAIs 3.1.12-1 and 3.1.12-5.

For the torus, see the response to RAI 3.1.12-1.

RAI 3.1.12-5:

For Unit 1, the limiting locations are the reactor vessel equalizer, core spray, standby liquid control, feedwater, HPCI, RCIC, RWCI, and main steam piping. For Unit 2, the limiting locations are the residual heat removal, feedwater, primary steam condensate drainage, and main steam piping. For each unit, the listed limiting locations for the Class 1 boundary don't add up to nine locations as stated in the LRA. Provide the missing locations and provide the basis for the difference in limiting locations between the two units.

RESPONSE TO RAI 3.1.12-5:

The intent of Section A.1.12.1 of the LRA was to indicate that the CCTLP monitored the torus and four RPV locations on each unit, plus a total of nine Class 1 piping locations. The list of nine (total for both units) Class 1 locations is provided in Section 4.2.2. If a piping system is monitored for fatigue on one unit and not the other, it is because the maximum design CUF for the piping on one unit is greater than 0.10 but not on the other. The five locations on Unit 1 and four locations on Unit 2 are described below with an explanation of the differences.

Differences between Units in Piping Monitored for CUF

Piping Description	Monitored for Unit 1	Monitored for Unit 2
Reactor vessel equalizer piping	Yes	No, Max CUF = 0.0092
Core spray piping from the reactor vessel to the 2nd isolation valve outside primary containment	Yes	No, Max CUF = 0.0136
Standby liquid control piping	Yes	No, Max CUF = 0.0017
Residual heat removal from the recirculation suction piping to the main isolation valve outside primary containment	No, Max CUF = 0.0689 This piping is included in a calculation for Unit 1 Recirculation Loop A	Yes originally, but subsequent to the LRA submittal, this piping was removed from the program. See Appendix B, Section 1.12
Primary steam condensate drainage	No, Max CUF = 0.0324	Yes
Feedwater piping	Yes This calculation for feedwater piping includes Class 1 portions of HPCI, RCIC, and RWCU from where they tie into feedwater piping back to the next anchor past an isolation or check valve.	Yes Does not include HPCI, RCIC, or RWCU because the Unit 2 feedwater piping changes to Class 2 prior to HPCI, RCIC, and RWCU connections to feedwater.
Main steam piping including HPCI & RCIC branch piping	Yes	Yes

RAI 3.1.12-6:

Provide a discussion of the engineering evaluations that are performed to disposition the locations projected to exceed a CUF of 1.0 for the next operating cycle.

RESPONSE TO RAI 3.1.12-6:

See Appendix B, Section 1.12.

PLANT SERVICE WATER AND RHR SERVICE WATER INSPECTION PROGRAM

RAI 3.1.13-1:

In Section A.1.13.1 of the LRA, the applicant stated that the Plant Service Water (PSW) and RHR Service Water (RHRSW) Inspection Program includes inspection for the aging effect of flow blockage caused by fouling of the plant service water and RHR SW systems. Describe how the AMP detects, monitors and trends this aging effect and describe the acceptance criteria.

RESPONSE TO RAI 3.1.13-1:

See Appendix B, Section 1.13.

RAI 3.1.13-2:

In Section A.1.13.1 of the LRA, the applicant stated that the PSW and RHRSW Inspection Program is designed to detect wall thickness degradation or fouling in the PSW and RHRSW systems. However, in Section A.1.13.4, of the LRA, the applicant also took credit for that inspection program as AMP for the aging effects of cracking and loss of heat exchanger performance. Since cracking can be caused by different mechanisms (e.g., thermal fatigue, vibration fatigue, or stress corrosion), specify the mechanism causing the cracking referenced in that section. In addition, clarify the scope and applicability of that AMP. Identify the parameters to be inspected/monitored and describe how the activities (including sampling and frequencies of the activities performed) in that AMP would detect aging effects of cracking and loss of heat exchanger performance. Also, describe the associated monitoring and trending, the acceptance criteria, as well as the operating experience with that AMP, as it applies to the applicable components for the referenced aging effects.

RESPONSE TO RAI 3.1.13-2:

The cracking referenced in LRA Section A.1.13.1 is related to stress corrosion and vibration fatigue in heat exchanger components only.

Also, see Appendix B, Sections 1.13 and 3.6.

RAI 3.1.13-3:

In Section A.1.13.3 of the LRA, the applicant referenced several documents containing applicable acceptance criteria, but without specifying these criteria. List all the acceptance criteria which are specifically applicable to this AMP.

RESPONSE TO RAI 3.1.13-3:

See Appendix B, Section 1.13.

RAI 3.1.13-4:

In Sections C.2.2.6.1, C.2.2.6.2, C.2.2.6.3, and C.2.2.6.4 of the LRA, it was indicated that, in the past, "15 deficiencies on E11 and 155 deficiencies on P41 systems were found" in the plant and RHRSW systems at Hatch. A review of the industry-wide data in the Nuclear Plant Reliability Data System has indicated that similar experience was observed in other plants. However, in these plants since about 1991, there was an obvious decreasing trend of failures. Describe the trend of failures observed in the past 10 years at Hatch.

RESPONSE TO RAI 3.1.13-4:

Industry service water systems report data generally shows a decreasing trend during the years immediately following issuance of GL 89-13. SNC also notes that this trend represents a reversal from the trend observed in the years preceding issuance of the GL.

However, the decreasing trend noted in this RAI is not relevant to the effectiveness of an AMP. For example, it must be noted that NPRDS data include deficiencies in both active and passive components. Further, there does not appear to be conformity among the plants in reporting service water system data. Review of the data shows that failure and cause descriptions were often too vague to evaluate, and in some cases, failures may have been misdiagnosed.

The databases available for Plant Hatch operating experience reviews actually covered the recent 10 years in two sequential 5-year periods. The second, and most recent, period contained approximately 50% more items that the older records. This change is due, not to the existence of more problems to report, but to there being a lower threshold for reporting during the more recent period. In addition, data from the more recent period contained improved descriptions of the condition, thus allowing a more definitive review for age-related degradation.

Therefore, SNC concentrated on site-specific inspection result trends for service water components within the scope of license renewal. Specifically, the AMPs concentrate on trends such as wall thinning, in order to preclude failures, rather than on trending failures after the fact as in NPRDS.

SNC concluded that there were many factors outside the scope of license renewal that may have affected what appeared to be an obvious trend in the NPRDS data. That, coupled with the usefulness of plant specific data and the maturation of the condition reporting processes, led SNC to conclude that only the last five years of condition reports would provide meaningful data for the operating experience reviews.

RAI 3.1.13-5:

The inspection program description states that inspection frequencies are determined by evaluating the trends in wall thickness reduction. Discuss the size of the sample population, the criteria used to select the sample population, and the criteria used to adjust the inspection frequency and lot size.

RESPONSE TO RAI 3.1.13-5:

The criteria used to adjust the inspection frequency and lot size, and the criteria used to select the sample population are described in Appendix B, Section 1.13.

PRIMARY CONTAINMENT LEAKAGE RATE TESTING PROGRAM

RAI 3.1.14-1:

Page A.1-17 of the LRA states that the Primary Containment Leakage Rate Testing Program applies to all 10 CFR 50 Appendix J, Option B leakage rate testing requirements for systems, structures, and components within the scope of license renewal. 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." In addition, provide the bases for any exceptions to these regulatory positions.

RESPONSE TO RAI 3.1.14-1:

See Appendix B, Section 1.14. The program provides for the implementation of all 10 CFR 50 Appendix J, Option B leakage rate testing requirements, as required by the Unit 1 and Unit 2 Technical Specifications. The program was developed through the use of 10CFR50, Appendix J, Option B, Regulatory Guide 1.163, NEI 94-01, and ANSI/ANS 56.8-1994.

The program describes the implementation and documentation requirements for the performance of leakage rate tests, including frequency of testing and leakage acceptance criteria based on requirements and guidance established in the documents referenced above, and NRC approved exemptions.

Criteria are defined for establishing Type A, Type B, and Type C test frequencies and administrative leakage limits, based on 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 Specifications amendments and exemptions. No exceptions are taken to regulatory positions C.1 through C.4 of RG 1.163.

RAI 3.1.14-2:

Page A.1-17 of the LRA states, "Type A tests are performed in accordance with ANSI/ANS 56.8 1994 and/or Bechtel Topical Report BN-TOP-1 and implemented through plant procedures." To what extent are the provisions of the above standard and report incorporated by the Type A tests performed as part of the Primary Containment Leakage Rate Testing Program?

RESPONSE TO RAI 3.1.14-2:

Primary containment Type A tests are performed in accordance with BN-TOP-1, which has been incorporated into plant procedures. Requirements for a Type A test, as described in ANSI/ANS 56.8-1994, have not been incorporated into plant procedures.

Also, see the response to RAI 3.6-2.

BOILING WATER REACTOR VESSEL AND INTERNALS PROGRAM

RAI 3.1.15-1:

BWRVIP has submitted 12 guidelines for staff review that constitute a generic program for managing aging effects in BWRs. Of these 12, Hatch references all but 3 (i.e., BWRVIP-25, Core Plate Inspection and Flaw Evaluation Guidelines, BWRVIP-42, BWR LPCI Coupling Inspection and Flaw Evaluation Guidelines, and BWRVIP-49, Instrument Penetration Inspection and Flaw Evaluation Guidelines). Discuss the plant-specific program that Hatch will utilize to manage the age related degradation (ARD) effects of the core plate, the low pressure coolant injection coupling, and vessel instrument penetrations.

RESPONSE TO RAI 3.1.15-1:

SNC followed the guidance contained in each of the subject BWRVIP documents.

BWRVIP-25 was used to evaluate the core plate for both units. BWRVIP-25 does not require inspections of the core plate if seismic wedges are in place. Both units have seismic wedges that were installed as part of shroud repair activities. Therefore no inspections/aging management activities are required and for that reason, BWRVIP-25 was not referenced.

Neither unit has LPCI couplings. Therefore, BWRVIP-42 is not applicable.

BWRVIP-49 concluded that the ASME Section XI requirements for penetrations were adequate. SNC will continue to meet the Section XI requirements as identified in the ISI program description. Thus, BWRVIP-49 is being fully implemented.

RAI 3.1.15-2:

The Hatch submittal states that "the reactor vessel 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. For Unit 1 only, the top guide is also included." Discuss why the Unit 2 top guide is not within the scope of license renewal.

RESPONSE TO RAI 3.1.15-2:

BWRVIP-26 includes a provision that top guide hold-down devices need not be inspected if it can be shown that the top guide will not lift under faulted load conditions. Based on the configuration for Unit 2, the hold-down device is the only portion of the top guide that would be considered for inspection. Based on the original design conditions, Unit 2 was shown to not require inspection, and thus, was not referenced in the LRA.

However, SNC is re-evaluating the top guide hold-down device lift. The preliminary analysis shows that the Unit 2 top guide also may lift under faulted conditions. If the preliminary results are confirmed, SNC will use BWRVIP-26 inspections for both Units.

RAI 3.1.15-3:

The Hatch submittal states that "the requirements of Section XI of the ASME Boiler and Pressure Vessel Code apply to attachments welded to the RPV, welded core support structures, and penetrations. In most cases, the BWRVIP Program is more comprehensive than Section XI requirements for use on BWR internals." Identify and discuss the exceptions to the BWRVIP program that Hatch is taking with regards to this statement, if any.

RESPONSE TO RAI 3.1.15-3:

SNC has not identified any exceptions regarding the implementation of the BWRVIP documents credited for aging management at this point in time. Consistent with the BWRVIP members commitment, when NRC issues its final SER on a BWRVIP I&E document as submitted, and obtains BWRVIP acceptance, SNC will identify any exceptions within 45 days of the SER issuance and BWRVIP acceptance.

RAI 3.1.15-4:

The Hatch submittal states that "the BWRVIP Program for internals subject to license renewal as implemented at Plant Hatch employs the BWRVIP Program criteria documented in the NRC SERs, except where specific exception has been identified to the NRC." Identify and discuss the exceptions to the BWRVIP program that Hatch is taking with regards to this statement, if any.

RESPONSE TO RAI 3.1.15-4:

The statement was placed in the LRA based on discussions between representatives of NRC License Renewal Branch and EMCB, and BWRVIP regarding level of detail to be provided in LRAs regarding BWRVIP-related topics. No exceptions to the BWRVIP program have been taken at this point in time. Consistent with the BWRVIP members commitment, when an NRC issues its final SER on a BWRVIP I&E document as submitted, and obtains BWRVIP acceptance, SNC will identify any exceptions within 45 days of the SER issuance and BWRVIP acceptance.

RAI 3.1.15-5:

The Hatch submittal states that "cracking is the aging effect managed by the BWRVIP Program." The BWRVIP program also discusses fatigue effects. Discuss the exceptions to the BWRVIP program that Hatch is taking with regards to fatigue, if any.

RESPONSE TO RAI 3.1.15-5:

No exceptions have been taken. Cracking is the effect being managed, regardless of cause.

WETTED CABLE ACTIVITIES

RAI 3.1-16-1:

A phase-to-ground fault event on a 5kV cable with ethylene-propylene-insulation occurred at Davis-Besse in October of 1999. It appears that the most likely degradation mechanism is intrusion of ground water into the cable over a period of time. The staff is interested in this cable failure because there are potential generic implications for cable failures caused by aging at other nuclear power plants. This cable failure has been addressed as an emerging issue in previous license renewal reviews. Accordingly, identify the type of cable insulation and jacket material that is used for the in-scope 4kV power cables and transformer feeder cables that are subject to wetted cable conditions.

RESPONSE TO RAI 3.1-16-1:

For in-scope cables in outdoor duct runs that are subject to wetted cable conditions, the insulation material is EPR and the jacket material is hypalon.

RAI 3.1-16-2:

In addition to the megger and polarization index testing that is periodically performed, discuss whether Doble power factor testing and partial discharge testing will be performed on in-scope cables that have been subjected to wetted conditions in order to determine the integrity of the cable insulation.

RESPONSE TO RAI 3.1-16-2:

Doble power factor testing and partial discharge testing are not performed as a part of the wetted cable activities, and are not planned to be performed at this time.

RAI 3.1-16-3:

Discuss how the wetted cable activity parameters are monitored and trended over time to assure that the cable insulation meets the acceptance criteria.

RESPONSE TO RAI 3.1-16-3:

See Appendix B, Section 1.16.

RAI 3.1-16-4:

Provide the acceptance criteria and the basis for the acceptance criteria for testing that is performed as part of the wetted cable activities.

RESPONSE TO RAI 3.1-16-4:

See Appendix B, Section 1.16.

RAI 3.1-16-5:

Provide a discussion of plant-specific and industry-wide experience relative to the wetted cables activities program at Hatch.

RESPONSE TO RAI 3.1-16-5:

Section 3.7 of DOE report SAND96-0344, "Aging Management Guideline for Commercial Nuclear Power Plants – Electrical Cable and Terminations," includes an industry-wide operating experience review of failures or aging of electrical cable and terminations that includes NRC generic communications and LERs, along with the INPO NPRDS database. NRC Inspection Reports, ERRs, GE SILs, and the EPIX database for failures or aging of electrical cable were also reviewed. Results of the NPRDS and EPIX database searches were bounded by the results obtained from DOE SAND96-0344. See Section C.2.5.4 of the LRA for plant-specific operating experience. See Appendix B, Section 1.16, for details of the Plant Hatch wetted cable activities.

REACTOR PRESSURE VESSEL MONITORING PROGRAM

RAI 3.1.17-1:

The LRA indicates that the Hatch RPV material surveillance program may be altered prior to operation during the renewal period. The LRA also indicates that BWRVIP is developing an Integrated Surveillance Program (ISP) and the surveillance program will be provided to the NRC for review and approval.

Address the following attributes of the RPV surveillance program for the license renewal term:

a. Capsules must be removed periodically to determine the rate of embrittlement and at least one capsule must be removed with a neutron fluence not less than once or greater than twice the peak beltline neutron fluence at the expiration of the license renewal period. Capsules must contain material to monitor the impact of irradiation on the limiting beltline materials and must contain dosimetry to monitor neutron fluence. If capsules are not being removed from Hatch during the license renewal period, the applicant must provide operating restrictions (i.e., inlet temperature, neutron spectrum and flux) to ensure that the RPV is operating within the environment of the surveillance capsules, and must provide ex-vessel dosimetry for monitoring neutron fluence.

b. Will the existing Hatch RPV material surveillance program be modified to meet the above attributes during the license renewal period? Describe the Hatch RPV material surveillance program for the license renewal period.

c. Will Hatch be utilizing data from the BWRVIP ISP to monitor radiation embrittlement of its RPV? Does the BWRVIP plan to add any new capsules to the BWRVIP ISP? Either describe the ISP or provide a schedule for implementing the ISP at Hatch. Explain how the proposed ISP will satisfy the ISP criteria in Appendix H, 10 CFR Part 50, and the attributes discussed above.

RESPONSE TO RAI 3.1.17-1:

The following responses are numbered in accordance with the RAI above. The responses are dependent on the final resolution between NRC and the BWRVIP regarding the development and approval of an ISP.

The BWRVIP has developed an ISP and submitted it to NRC for review and approval. The ISP is documented in BWRVIP-78, "BWR Vessel and Internals Project: BWR Integrated Surveillance Program Plan," issued December 1999. One of the provisions of the ISP is for surveillance capsule material withdrawal and testing during the license renewal period.

a. SNC is aware of the provisions of Appendix H, and understands that the RPV must be operated within parametric limits that assure vessel integrity with regard to embrittlement and fracture toughness. However, there is not yet a demonstrated need to provide operating restrictions. Capsules will be removed during the renewal period, either as part of an ISP or as part of a plant-specific

RPV material surveillance program. See items b. and c. below, for additional detail.

b. The RPV monitoring program will be modified prior to operation in the renewal period. SNC plans to implement the provisions of the ISP currently described in BWRVIP-78. Should the ISP not be approved by NRC, or if it should be modified such that Plant Hatch is not covered by the ISP, then SNC will develop a RPV materials surveillance program for the renewal period.

c. As noted in item b., above, SNC plans to implement the ISP currently described in BWRVIP-78. As noted in Section 2.1 of BWRVIP-78, the ISP complies with the provisions of 10CFR50 Appendix H. The ISP currently provides for 13 capsules to be available for testing during the renewal period for the BWR fleet.

FIRE PROTECTION ACTIVITIES

RAI-3.1.18-1:

Section A.2.1 of the LRA indicates that the AMPs for the compressed gas based fire suppression systems and fire barriers for preventing fire propagation consist of condition and performance monitoring. It does not appear to the staff that condition and performance monitoring alone are sufficient to ensure that the aging effects are adequately managed. Clarify how these programs address all of the aging effects for these two commodities and provide the bases for this conclusion or propose additional aging management programs to ensure that all of the aging effects are adequately managed.

RESPONSE TO RAI-3.1.18-1:

LRA Section C.2.3 indicates that the credited programs include inspection activities for the compressed gas based fire suppression systems and fire barriers, and not performance monitoring alone. The first sentence of Section A.2.1.1 of the LRA could have also included inspection. Examples of other inspection activities are noted in the section. Also, see Appendix B, Section 2.1. For clarity, SNC has grouped program-related information from LRA Appendices A and C into Appendix B to these RAI responses.

RAI 3.1.18-2:

Provide the specific parameters for each component that is inspected or monitored as part of the (1) water-based fire suppression system, (2) diesel fuel oil system, and (3) compressed gas fire suppression systems.

RESPONSE TO RAI 3.1.18-2:

See Appendix B, Section 2.1.

RAI 3.1.18-3:

Discuss how the specific parameters inspected or monitored as part of the fire protection activities detect the aging effects (loss of material, cracking, flow blockage, and changes in material properties) that are managed by this AMP.

RESPONSE TO RAI 3.1.18-3:

See Appendix B, Section 2.1.

RAI 3.1.18-4:

The description of the fire protection activities does not specify the parameters that are monitored or trended in order to provide predictability of the extent of degradation and timely corrective or mitigative actions. Discuss the technique, frequency, and sample size of the parameters that are monitored and trended within the fire protection activities AMP.

RESPONSE TO RAI 3.1.18-4:

See Appendix B, Section 2.1.

RAI 3.1.18-5:

Specify the acceptance criteria and discuss the bases for each criteria for the parameters monitored in each fire protection system commodity group.

RESPONSE TO RAI 3.1.18-5:

See Appendix B, Section 2.1.

RAI 3.1.18-6:

In Section C.2.3 of the LRA, several deficiencies of the compressed gas fire protection system were found related to exterior corrosion of piping components in areas of coating degradation. These deficiencies were managed under the AMP for mechanical component external surfaces. Discuss the adequacy of the fire protection activities in managing the aging effects of this system.

RESPONSE TO RAI 3.1.18-6:

The external surfaces of these components are managed by the protective coatings program, not the fire protection activities. External coatings and paint are inspected per the industry guidance referenced in the protective coatings program, as described in Appendix B, Section 2.3. The protective coatings program was inadvertently omitted from Section C.2.3.3. Periodic inspections performed as a part of the protective coatings program are sufficient to detect degraded conditions that might occur. The corrective actions program requirements then result in appropriate actions being taken to remedy the detected condition. Protective coatings are maintained to prevent/mitigate corrosion of the base metal.

RAI 3.1.18-7:

Section A.2.1 of the LRA states that the water-based fire protection header loop piping is flushed on a regular basis. However, the acceptability of the automatic wet-pipe sprinkler systems, which are located in some portions of the plant, was not discussed. Discuss the surveillance procedure and criteria that will be used to verify that the wet-pipe sprinkler systems, which are required for compliance with 10 CFR 50.48, will remain operable throughout the period of extended operation. Furthermore, discuss the routine testing and trending of the closed sprinkler heads (wet-pipe systems) to ensure that pressure losses, resulting from aging effects, will not prevent automatic sprinkler operation.

RESPONSE TO RAI 3.1.18-7:

As part of the fire protection activities, a wet pipe sprinkler header flow test is performed (see Appendix B, Section 2.1). A header test valve has an orifice opening the same size as the sprinkler heads, and is located at the most distant point in the sprinkler system from the alarm valve. The test valve is opened to allow water to exit the system, resulting in observable flow and a reduction in sprinkler header pressure. Unobstructed water flow from the header test valve demonstrates that sprinkler heads and piping are not clogged from corrosion product debris. Obstructed water flow from the test valve indicates that sprinkler heads and piping may be clogged, and further investigation is required per the corrective actions program. The reduced header pressure activates an alarm in simulation of a fire, as if sprinkler heads had actually opened. The alarm valve actuates on low pressure, and charges the sprinkler header to replenish water exiting the system. The test proceeds until the alarm sounds (signifying that the alarm valve has actuated), or until 1.5 minutes have elapsed. If the results are not satisfactory, corrective action is initiated to remedy the condition. This periodic test establishes operability of the system by verifying simulated automatic system actuation. Sprinkler heads/spray nozzles are visually inspected for corrosion, excessive deposits, and encrustation (see Appendix B, Section 2.1), and replaced as required. The water based fire protection system is normally pressurized, with no flow. Since there is normally no flow in a wet pipe sprinkler header, automatic sprinkler operation is dependent on pressure decay as a result of sprinkler heads responding to a fire. The test described above periodically verifies automatic system actuation on header pressure decay.

Should component degradation be discovered, the corrective actions program requires a timely remedy, as well as trending for possible future mitigative actions.

RAI 3.1.18-8:

Section A.2.1 of the LRA states that the fire protection activities will be enhanced to include periodic inspection of the water suppression system strainers for flow blockage and loss of material. Provide a discussion of the enhanced surveillance requirements and associated sample size and frequency.

RESPONSE TO RAI 3.1.18-8:

The enhanced surveillance requirements for water suppression system strainers include visual inspection of internal strainer elements for loss of material and flow blockage due to various mechanisms such as corrosion and fouling. Elements are cleaned before being returned to service. If elements are found to be in an unacceptable condition that cannot be remedied by cleaning, then they must be repaired or replaced. The surveillance frequency is described in Appendix B, Section 2.1. Since all in-scope strainers are inspected, there is no "sample size."

RAI 3.1.18-9:

Provide justification for the absence of enhanced inspection programs for other components besides the water suppression system strainers such as the sprinklers, which do not have a design life that covers the period of extended operation.

RESPONSE TO RAI 3.1.18-9:

In general, enhanced inspection programs are deemed unnecessary because the existing programs adequately manage the aging effects of concern, as evidenced by the lack of significant deficiencies in the operating history. However, a one-time sprinkler heads inspection is to be performed for in-scope sprinkler heads, and is described in Appendix B, Section 2.1. Sprinkler heads/spray nozzles are periodically inspected for corrosion, deposits, and encrustation. Sprinkler heads/spray nozzles are replaced as required, based on the inspection results.

RAI 3.1.18-10 (Revised 10/06/00):

a. Section A.2.1 of the LRA states that the portion of the Plant Hatch fire protection activities credited for license renewal is that portion included in Appendix B of the FHA. Furthermore, Section A.2.1.2 states that the surveillance requirements and the associated frequencies are set forth in Appendix B of the FHA. In accordance with GL 86-10, the applicant's license condition allows for changes to the fire protection program without NRC approval (on the basis that changes do not constitute a decrease in the level of safety). Information regarding surveillance and frequency for each component subject to an AMR are important factors that aid the reviewer in making determinations regarding the acceptability of the fire protection aging management program. Please provide the surveillances/frequencies for the fire protection components that are subject to an AMR at Hatch.

b. Identify the passive long-lived components in the water-based and gaseous fire suppression systems. Also identify the tanks and the piping boundaries in the fire pump diesel fuel oil supply system and fire rated assemblies that are within the scope of license renewal.

RESPONSE TO RAI 3.1.18-10:

a. See Appendix B, Section 2.1.

b. The passive, long-lived components for the water based and gas based fire suppression systems, as well as the fire pump diesel fuel oil system are identified in Table 3.2.4-18 of the LRA. The tanks and piping boundaries for the fire pump diesel fuel oil system are identified on boundary drawing HL-11033 sheet 1. Fire rated assemblies include fire penetration seals and cable tray enclosures. A "spaces" approach was used for the fire penetration seals because of the large number of seals involved. All fire rated penetration seals, excluding those inside the Radwaste Building, are included in the scope of license renewal (see the response to RAI-2.3.4-FPS-8 for exclusion of the Radwaste Building fire suppressions systems). Cable tray enclosures that are included in-scope are identified by cable tray identification numbers in a plant procedure that forms part of the fire protection activities.

FLOW ACCELERATED CORROSION PROGRAM

RAI 3.1.19-1:

Section A.2.2 of the LRA states that the Flow Accelerated Corrosion Program is designed to monitor aging effects due to loss of material caused by FAC. List the major types of components susceptible to FAC which are included in the program and specify their materials of construction and the environment to which they are exposed.

RESPONSE TO RAI 3.1.19-1:

See Appendix B, Section 2.2.

RAI 3.1.19-2:

The Flow Accelerated Corrosion Program described in Section A.2.2 of the LRA is based on the EPRI recommendations and consists of a method for predicting material loss by the components susceptible to FAC, and of subsequent measurements, the degree of this loss by ultrasonic testing (UT), radiography (RT) or visual examination (VT). To understand the specific nature of the program, provide the following additional information:

What type of predictive methods are used for determining degraded components by FAC? Are these methods based on computer predictive codes and/or some other procedures? If an industry-wide program is used, specify the program, and if it is a plant specific methodology, give a detailed description of the program.

RESPONSE TO RAI 3.1.19-2:

The in-scope piping greater than two inches in diameter that is susceptible to FAC, and that can be modeled, is modeled using CHECWORKS computer software. The CHECWORKS software was developed by EPRI to determine a predicted wear rate for each piping component. A report can be generated by the program, ranking all components in a process line in order of decreasing predicted wear rate. CHECWORKS predicts wear rates for each component, and incorporates factors such as component configuration, materials, water chemistry, flow rates, and total operating hours.

The FAC program does include components other than piping which are found to be susceptible to FAC. The program includes mechanical components that are installed in piping lines that are subjected to conditions that promote the loss of wall thickness due to FAC. In-scope piping that is two inches or less will be excluded from the computer modeling process, since CHECKWORKS does not have the capability to model such piping. For this piping, the examination method and frequencies for the enhanced FAC program will be based on industry and plant specific operating experience. Computer modeling will still be used to predict the wear rate and frequency of examination for in-scope piping components greater than two inches.

RAI 3.1.19-3:

In Section A.2.2 of the LRA, it is stated that the acceptance criteria for wall thickness of the FAC affected components will be based upon the governing code of record for the piping. Specify these codes and their applicability to other components besides piping.

RESPONSE TO RAI 3.1.19-3:

Plant Hatch design codes of record include the following:

- USAS B31.7, 1969 (Unit 1 only).
- ASME Boiler and Pressure Vessel Code, Section III, 1971 through 1971 addenda (Unit 2 only).
- USAS B31.1, 1967.

RAI 3.1.19-4:

The proposed enhancement of the Flow Accelerated Corrosion Program, described in the LRA, will include additional piping for certain systems that are already included in the current program and their examinations will be limited to plant-specific operating experience as opposed to computer modeling. Does the program include components other than piping which are found to be susceptible to FAC? Why will the computer modeling be abandoned in examining components in the enhanced program?

RESPONSE TO RAI 3.1.19-4:

See the response to RAI 3.1.19-2.

RAI 3.1.19-5:

Provide a description and basis of the proposed enhanced examination methods and frequencies and compare with those in the current FAC program.

RESPONSE TO RAI 3.1.19-5:

There are no enhancements to the examination methods and frequencies. The enhanced program refers to the additional scope not currently included in the FAC program.

RAI 3.1.19-6:

In Section A.2.2.5 of the LRA, the applicant states that, for Unit 2 only, portions of the radioactive decay holdup volume will be included in the enhanced FAC program. Provide the bases for including portions of the radioactive decay holdup volume (main steam and steam line drains, and condensate drains) in the Hatch Unit 2 FAC program. Also provide the bases for not including these components in the Hatch Unit 1 FAC program.

RESPONSE TO RAI 3.1.19-6:

See the response to scoping RAI 2.3.5-MC-1. The basis for inclusion in one unit and not the other is a matter of unique CLB differences between the two units.

RAI 3.1.19-7:

Since the EPRI guidelines to monitor FAC are too general, the staff must review the details of the program pertaining to safety-related components to determine its adequacy and acceptability. Describe, in detail, how the FAC program applies to the safety-related components that are susceptible to erosion-corrosion.

RESPONSE TO RAI 3.1.19-7:

In order to determine which plant systems are considered susceptible to FAC, the FAC program initially considered all systems (safety related and nonsafety-related) as candidates. Each system is then screened for exclusion, based on certain criteria, as follows:

1. Non-Water Systems – Systems that do not transport water or steam are exempt from the program.

2. High Quality Steam Systems – Systems that transport superheated or "dry" steam (>99.5% quality) are exempt from the program.

3. High Chromium Materials – Systems constructed of stainless steel, or low alloy steels with a chromium content 1-1/4% or greater, may be excluded from the program.

4. Raw Water Systems – These systems have a high dissolved oxygen content, and therefore, are not susceptible. Examples of such systems are service water, circulating water, and fire protection.

5. Energy Level – Single phase systems with operating temperatures less than 200 degrees Fahrenheit are excluded.

6. Low Usage Systems – Systems which are known to operate 2% or less of the time may be excluded from the program, unless it is uncertain if the operating time is less than 2%, flashing conditions exist, or industry experience indicates the system is susceptible.

If none of the above criteria apply, a system, and the components that make up the system, is considered susceptible.

This screening task was performed for all systems, and the results documented in a program manual. Based on the above criteria, this manual lists the systems, or portions of systems for both units, that are designated as susceptible to FAC. See Appendix B, Section 2.2, for a discussion of the FAC program scope.

RAI 3.1.19-8:

What is the operating experience of FAC at Hatch? Identify the components and environments where high FAC rates have been found to-date and describe, in detail, what corrective actions have been taken.

RESPONSE TO RAI 3.1.19-8:

See Appendix B, Section 2.2.

PROTECTIVE COATINGS PROGRAM

RAI 3.1.20-1:

In order to evaluate the adequacy of this program, the staff requests information on the maximum interval between inspection of non-service Level I structures and components, including buried pipe.

RESPONSE TO RAI 3.1.20-1:

The protective coatings program is being enhanced to include non-service Level I structures and components. The inspection frequencies will be established using operating experience and expected environmental conditions. See Appendix B, Section 2.3, for a description of the protective coatings program. Inspection of buried pipe will be accomplished by the PCIA. The PCIA will be based on opportunity, not frequency. See Appendix B, Section 3.5, for a description of PCIA.

RAI 3.1.20-2:

In order to evaluate the adequacy of this program, the staff requires justification for the use of only visual inspection of buried environment.

RESPONSE TO RAI 3.1.20-2:

Visual inspection of buried commodities is accomplished with the PCIA See Appendix B, Section 3.5. The PCIA will use visual inspection techniques (similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210) to detect corrosion of metallic components. Visual inspection of uncovered buried commodities will be adequate to identify damaged or degraded coatings and any subsequent loss of material due to corrosion.

RAI 3.1.20-3:

Please provide specific examples of loss of material that were detected using the protective coatings program. Of particular interest, what is the operating experience on buried pipe at Hatch?

RESPONSE TO RAI 3.1.20-3:

The current protective coatings program at Plant Hatch is focused largely on the periodic inspection of the condition of service level I coatings, and not on the recording of loss of base material. Since service level I coatings are, by definition, found only inside the primary containment, no buried piping was included in these inspections. The enhanced protective coatings program focuses on the loss of the base material as well as the condition of the coating, and includes inspection of non-service level I coatings. See Appendix B, Section 2.3, for more information on the enhanced program, including a discussion of operating experience with regard to coatings on buried pipe.

EQUIPMENT AND PIPING INSULATION MONITORING PROGRAM

RAI 3.1.21-1:

The equipment and piping insulation monitoring program provides for inspection of the insulation for deterioration due to loss of material, cracking, and change in material properties. The application states that the equipment and piping insulation monitoring program provides timely tests/inspections for detecting degradation. What tests and inspections are performed? What parameters are inspected or monitored? Is the insulation removed to inspect it? How is the proposed inspection able to detect cracking, intrusion of water, compaction/settling, and thermal degradation?

RESPONSE TO RAI 3.1.21-1:

See Appendix B, Section 2.4, for discussion of tests, inspections, parameters monitored, and how the inspections detect the aging effects of concern. Insulation does not prevent implementation of inspections conducted pursuant to the equipment and piping insulation monitoring program.

RAI 3.1.21-2:

The staff requests the applicant specify/explain how the parameters inspected and monitored provide detection of the aging effects of loss of material, cracking, or change in material properties.

RESPONSE TO RAI 3.1.21-2:

See Appendix B, Section 2.4.

RAI 3.1.21-3:

The staff requests the applicant to discuss the technique, frequency and sample size of the parameters monitored and/or trended which are credited in the equipment and piping insulation monitoring program.

RESPONSE TO RAI 3.1.21-3:

See Appendix B, Section 2.4.

RAI 3.1.21-4:

The applicant did not specify the acceptance criteria for the parameters upon which the need for corrective actions will be evaluated. The staff requests the applicant to specify the acceptance criteria and discuss the bases for the criteria.

RESPONSE TO RAI 3.1.21-4:

See Appendix B, Section 2.4.

RAI 3.1.21-5:

The applicant needs to provide information to demonstrate that the equipment and piping insulation monitoring program provides reasonable assurance that the aging effects will be 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.

RESPONSE TO RAI 3.1.21-5:

See Appendix B, Section 2.4.

STRUCTURAL MONITORING PROGRAM

RAI 3.1.22-1:

Describe the criteria for assessing or categorizing the overall condition of the structures and components that are monitored as part of the structural monitoring program (Appendix A, Section A.2.5). Include specific examples such as indications of cracking or spalling on concrete surfaces; corrosion or excessive deflection of structural steel components; and changes in material property or cracking of sealants.

RESPONSE TO RAI 3.1.22-1:

See Appendix B, Section 2.5.

RAI 3.1.22-2:

Proactive monitoring and understanding of trending behavior is needed to monitor structural aging to allow corrective actions to be taken prior to exceeding acceptance criteria. Describe the monitoring and trending activities that are used as part of the structural monitoring program (Appendix A, Section A.2.5) to track the extent and rate of degradation and their relationship to the acceptance criteria.

RESPONSE TO RAI 3.1.22-2:

See Appendix B, Section 2.5.

RAI 3.1.22-3:

As a guidance document, the structural monitoring program (Appendix A, Section A.2.5) cites ACI 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures." In addition, the description of the acceptance criteria for the structural monitoring program (SMP) states that the framework for the SMP is consistent with industry guideline NEI 96-03 and that the NEI 96-03 guidance was conditionally accepted in Regulatory Guide 1.160. Regulatory Guide 1.160 (Revision 2), "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," endorses NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," but not NEI 96-03, "Guideline for Monitoring the Condition of Structures at Nuclear Power Plants," since this document was never completed. Unlike the guidance provided by the documents ACI 349.3R-96 and ANSI/ASCE 11-90, "Guideline for Structural Condition Assessment of Existing Buildings," none of the other documents listed above (NUMARC 93-01, NEI 96-03, RG 1.160) provide specific and detailed acceptance criteria for the commodity groups that utilize the structural monitoring program for aging management. For each commodity group that utilizes the structural monitoring program, provide a description of the criteria that are used to (1) assess the severity of the observed degradations and (2) determine whether corrective action is necessary.

RESPONSE TO RAI 3.1.22-3:

See Appendix B, Section 2.5.

RAI 3.1.22-4:

Since structural condition management necessarily involves "engineering judgement," provide a description of the training, technical qualifications, and practical experience of the personnel that (1) perform the structural monitoring program (Appendix A, Section A.2.5) walkdown activities for structures and components and (2) evaluate the adequacy of the walkdown procedures and interpret the walkdown findings.

RESPONSE TO RAI 3.1.22-4:

The following excerpt on Examiner Qualifications is taken from the implementing document for the SMP.

> "**D. Examiner Qualifications**
>
> "The quality and value of results obtained from an evaluation of an existing structure are dependent to a great extent on the qualifications and capabilities of the evaluation team. To ensure that the evaluations are sufficiently implemented, minimum qualifications of the personnel involved are provided. The following qualifications are provided as a guide in selecting an evaluation team:
>
> - civil / structural engineering graduate with 5 years related civil/structural experience or a registered professional engineer that is a civil / structural engineering graduate with related civil/structural experience
> - experienced and knowledgeable in the design, evaluation and in-service inspection of structures
> - experienced and knowledgeable of performance requirements of safety-related structures
> - experienced and knowledgeable of aging and degradation mechanisms and long-term performance issues
>
> "In addition, the lead inspector of the evaluation team will be trained in the use of the Westinghouse Owner's Group, Life Cycle Management / License Renewal Program. This is a self study course consisting of printed material and video tapes of degradation. The training materials include implementation guides, aging assessment for structures and components, aging assessment field guide for structural monitoring, workshop notes and video tapes for structural monitoring and buried commodities. Other members of the team will use the above documents for reference.
>
> "All evaluation team members will be trained to the requirements of this procedure prior to performing examinations and/or evaluations."

The SMP implementing procedure outlines, in detail, the evaluation methods and acceptance criteria to be used in the walkdowns. Detailed records, along with photographs, as necessary, have been kept of the several walkdowns already performed for the Maintenance Rule.

In the NRC inspection of the SMP performed in May 1997, the NRC indicated that it found the civil engineers that accompanied NRC inspectors were knowledgeable and qualified to perform structural evaluations.

RAI 3.1.22-5:

Provide a general description of the different walkdown procedures, checklists, or inspection forms, if any, that are provided to the personnel that perform the structure and component walkdowns as part of the Structural Monitoring Program (Appendix A, Section A.2.5), as required by Quality Assurance Criteria V of 10 CFR Part 50, Appendix B.

RESPONSE TO RAI 3.1.22-5:

Appendix B, Section 2.5, describes the structural monitoring program. The implementing document for the structural monitoring program provides a detailed description of the walkdown procedures, acceptance criteria, evaluation of results and checklists, and is available on site for NRC review.

GALVANIC SUSCEPTIBILITY INSPECTIONS

RAI 3.1.23-1:

Since the galvanic susceptibility inspections are one-time inspections of a given sample that are intended to provide objective evidence that the applicable aging effects are being adequately managed, provide the sample size, characteristics of the sample population, the basis for selection of the sample and the criteria for sample expansion upon discovery of the aging effects.

RESPONSE TO RAI 3.1.23-1:

See Appendix B, Section 3.1.

RAI 3.1.23-2:

Section A.3.1.3 of the LRA states that "inspection procedures and acceptance criteria will be developed using the applicable sections of the ASME Code..." Will the procedures and acceptance criteria apply to systems and components outside of Section XI? Will the inspection procedure and the acceptance criteria use as stated "applicable sections of the ASME Code" even though the systems and components are outside the Scope of Section XI? Provide your acceptance criteria for each of these inspections including their bases to mitigate effects of aging prior to loss of intended function of the component during the renewal term.

RESPONSE TO RAI 3.1.23-2:

SNC does not plan to inspect non-Code systems and components in accordance with ASME Code procedures and acceptance criteria. Rather, SNC is using the design codes applicable to each system and component to establish inspection procedures and acceptance criteria. See Appendix B, Section 3.1.

RAI 3.1.23-3:

Clarify whether the galvanic susceptibility inspections cover bolting in mechanical joints (non-ISI boundary) susceptible to the aging effects of loss of material and cracking.

RESPONSE TO RAI 3.1.23-3:

Galvanic susceptibility inspections do not single out bolts. Coated bolts are included in the protective coatings program, which manages loss of material. Stainless steel bolts are not susceptible to galvanic attack.

RAI 3.1.23-4:

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. Section C.1.2.2.1 of the LRA states that auxiliary system water environments (which include demineralized, suppression pool, spent fuel pool, and borated waters) which contain carbon steel and aluminum alloys may be susceptible to galvanic corrosion when electrically coupled to stainless steel components. Provide the rationale for excluding galvanic susceptibility inspection of aluminum-carbon steel, galvanized steel-carbon steel, cast austenitic-carbon steel, stainless steel-carbon steel couples for components in condensate transfer and storage system.

RESPONSE TO RAI 3.1.23-4:

SNC performed an AMR of the in-scope portions of the condensate transfer and storage system (P11), as shown in LRA Table 3.2.4-5. Galvanic corrosion is considered an aging mechanism for the Unit 1 system. Loss of material is the aging effect requiring management by the programs given in Table 3.2.4-5.

The Unit 1 CST is fabricated from aluminum alloys with galvanized steel tank flanges connected to stainless steel piping. Stainless steel bolting is used as indicated on the table. These dissimilar metal connections are the only locations potentially susceptible to galvanic corrosion in the P11 system. While demineralized water chemistry control is expected to prevent any galvanic corrosion, the CST inspection will inspect a sample of these potential areas of corrosion in a specific one-time inspection. See Appendix B, Section 3.4, for additional information.

RAI 3.1.23-5:

Galvanic corrosion occurs when two electrically coupled metal surfaces are characterized by different corrosion potentials in an electrolyte. Section C.1.2.4.1 of the LRA states that within river and well water environments, cast irons, among other materials, are susceptible to galvanic corrosion when electrically coupled to stainless steel components. The plant service water system contains cast iron and stainless steel components. Are cast iron pump casings in raw water or treated water environments also included within the Galvanic Susceptibility Inspection AMP? If not, what AMPs are credited in managing galvanic corrosion for these materials in these environments?

RESPONSE TO RAI 3.1.23-5:

The raw water environment includes river water and well water. The list of in-scope components having a river water environment does not include cast iron pump casings. Loss of material occurring by any process is adequately managed by the PSW and RHRSW inspection program, as stated in LRA Table 3.2.4-7. See Appendix B, Section 1.13, for a description of this program.

Fire protection system components, including cast iron pump casings, are exposed to the well water environment. The program credited for managing the effects of loss of material due to galvanic corrosion on these components is the fire protection activities. See Appendix B, Section 2.1, for a description of the fire protection activities.

There are no in-scope cast iron pump casings located in the treated water environment.

TREATED WATER SYSTEMS PIPING INSPECTIONS

RAI 3.1.24-1:

As stated in Section C.2.2.2, of the LRA, the treated water systems piping inspection 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 treated water program description in Section A.3.2, of the LRA, stated that the scope is limited to carbon and stainless steel tubing and piping, yet the applicant credits this program for managing aging effects for other components such as accumulators and valve bodies. Discuss how the scope of the program accounts for all carbon and stainless steel components exposed to a demineralized water environment.

RESPONSE TO RAI 3.1.24-1:

See Appendix B, Section 3.2.

RAI 3.1.24-2:

The same program description states that the program will examine a population of tubing and piping in the treated water systems. Discuss the size of the sample population and discuss the criteria which will be used to select the sample population.

RESPONSE TO RAI 3.1.24-2:

The overall sample population for the TWSPI will be divided into several smaller sample populations based on the material and internal environment. This will make each sample population independent of the other. That is, one population will not influence the size of the other. Each sample population will have unique selection criteria. Two examples of a sample population are carbon steel in torus water, and stainless steel in reactor water.

The types of in-scope components will be represented in the sample population, including piping, fittings, tubing, valves, pumps, welds, etc., as applicable.

Ultimately, the sample size will be determined from a selection of potential sample locations. These locations will be identified based on selection criteria that will assure the greatest probability of success in finding an aging effect, should it be present. The selection criteria consider factors such as most susceptible locations, locations that present high consequences associated with a failure without respect to susceptibility, plant and industry experience, etc. In addition, physical accessibility and radiation exposure levels will be considered in the selection process, as well. The sample size derived from the selection process will provide a population of sample locations that will qualitatively and quantitatively provide the necessary evidence to conclude whether aging is being adequately managed. Should unclear results be produced from the initial sample locations, the program also includes provisions for scope expansion so that a determination can be made of whether periodic monitoring and trending will be required.

RAI 3.1.24-3:

In Section C.2.2.2.1, of the LRA, the applicant credited the treated water systems piping inspections for managing erosion corrosion. Without additional information, the staff cannot support the use of a one-time inspection to manage erosion corrosion. Discuss how erosion corrosion, which in the staff's experience requires regular surveillance, can be managed by a one-time inspection. Also, clarify why Table C.2.2.2-2, under attribute #4, refers to the treated water systems piping inspections as providing for "periodic inspections of components susceptible to erosion corrosion . . ." This is not consistent with the description of the actual program in A.3.2 of the application which states that this program is a one-time inspection used to validate the chemistry control program, not manage erosion corrosion.

RESPONSE TO RAI 3.1.24-3:

In addition to responding to the RAI, this response provides a clarification of the erosion-corrosion aging mechanism for auxiliary systems.

As defined by SNC for auxiliary systems, erosion-corrosion encompasses flow related aging mechanisms such as erosion-corrosion, cavitation erosion, and impingement, and is potentially significant for carbon steel components in these systems. The general term, erosion-corrosion, includes all forms of accelerated corrosion in which protective surface films and/or the metal surface itself are removed by a combination of fluid-induced mechanical wear, or abrasion plus corrosion. Erosion-corrosion normally occurs when the solution velocity exceeds a threshold value, and is potentially significant in auxiliary systems in areas of high turbulence or pressure fluctuations.

The term FAC is used by SNC to specifically describe the thinning of carbon steel alloys where there is no threshold solution velocity. FAC is a phenomenon that is a function of many parameters, including water chemistry (pH, oxygen and temperature), service hours, material composition (Cr, Cu and Mo content), and hydrodynamics (steam quality, velocity and geometry). Based on this definition, and the results of system susceptibility evaluations by the FAC program, FAC is not applicable to auxiliary systems such as demineralized water. Also, see the response to RAI 3.1.19-7.

Attribute #4 of Table C.2.2.2-2 should state that the TWSPI AMP provides for a one-time inspection of components susceptible to erosion and similar mechanisms.

The TWSPI is being credited to inspect locations that have the potential for loss of material due to erosion-corrosion, as described above, since these locations are not identified as susceptible to FAC by the FAC program. Plant Hatch operating experience indicates that loss of material due to erosion-corrosion in demineralized water systems is limited to areas downstream of orifices and throttle valves, where significant turbulence and pressure fluctuations exist. Thus, these systems are generally not considered to be susceptible to wall thinning, and a large number of inspection points is not required. In most cases, design changes have been implemented to reduce turbulence and pressure fluctuations in areas where past problems occurred, thereby, significantly reducing the potential for recurrence of unacceptable wall thinning. Therefore, inspections accomplished in accordance with the TWSPI are considered adequate to confirm that no areas of significant wall thinning exist.

RAI 3.1.24-4:

The applicant stated that the Treated Water Systems Piping Inspections provide for condition monitoring via one-time examinations to provide evidence that existing chemistry control is managing aging in piping that is not examined under another inspection program. Specifically clarify what aging in piping, other than cracking and loss of material, is being referred to here.

RESPONSE TO RAI 3.1.24-4:

As stated in LRA Section A.3.2.4, cracking and loss of material are the only two aging effects that will be managed by the TWSPI.

RAI 3.1.24-5:

The applicant states that inspections will be conducted using techniques that may include, but not be limited to, volumetric or destructive examination. The applicant also states that mechanical joints may be inspected using an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210. Specify, for each examination method used, which parameters are examined or monitored and how the examination results will provide detection of the aging effects of cracking and loss of material. Discuss the sample size of the piping selected for each examination.

RESPONSE TO RAI 3.1.24-5:

Visual testing similar to VT-1 will be used to monitor for loss of wall thickness due to excessive corrosion product buildup, crevice and pitting corrosion, and erosion. The visual examination results will provide initial evidence whether internal surfaces of piping components are in a degraded condition, whereas a precise measurement may be needed to quantify the extent of the degradation. Volumetric examinations, ultrasonic testing, or radiography, may be used on locations where access does not permit direct or indirect visual examination, or when visual inspections results warrant additional examination methods.

See the response to RAI 3.1.24-2 for a discussion of sample size.

RAI 3.1.24-6:

The applicant did not provide the acceptance criteria for the treated water systems piping inspection upon which corrective actions or sample expansion may be required if warranted by the examination results. Specify the acceptance criteria and discuss the bases for the criteria.

RESPONSE TO RAI 3.1.24-6:

See Appendix B, Section 3.2.

GAS SYSTEMS COMPONENTS INSPECTIONS

RAI 3.1.25-1:

Since the 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, provide the sample size, the basis for selection of the sample and the criteria for sample expansion upon discovery of the aging effects.

RESPONSE TO RAI 3.1.25-1:

See Appendix B, Section 3.3.

RAI 3.1.25-2:

Section A.3.1.3 of the LRA states that "inspection procedures and acceptance criteria will be developed using the applicable sections of the ASME Code..." Will the procedures and acceptance criteria apply to systems and components outside of Section XI? Will the inspection procedure and the acceptance criteria be used as stated in "applicable sections of the ASME Code" even though the systems and components are outside the scope of Section XI? Provide your acceptance criteria for each of these inspections, including their bases to mitigate effects of aging prior to loss of intended function of the component during the renewal term.

RESPONSE TO RAI 3.1.25-2:

See Appendix B, Section 3.3.

RAI 3.1.25-3:

Clarify whether the gas systems component inspection program covers bolting in mechanical joints (non-ISI boundary) susceptible to aging effects of loss of material and cracking.

RESPONSE TO RAI 3.1.25-3:

The GSCI do not cover bolting in mechanical joints. The GSCI are intended to be one-time inspections of interior surfaces of in-scope, gas-bearing components.

RAI 3.1.25-4:

The applicant identified stress corrosion cracking as an applicable aging effect for some components and systems exposed to a wetted gas environment. The gas systems component inspection consists of a visual inspection, which the staff finds inadequate to detect stress corrosion cracking or intergranular attack. Due to their morphology, surface or volumetric inspections must be used to identify these mechanisms. Discuss the acceptability of a VT-1 inspection to detect stress corrosion cracking and intergranular attack.

RESPONSE TO RAI 3.1.25-4:

As described in Appendix B, Section 3.3, the GSCI allow for inspections using methods other than visual. For those stainless steel components that normally operate at temperatures above 140 °F, and that contain wetted gases, volumetric examinations may be used as part of the inspections to detect the presence of SCC.

CONDENSATE STORAGE TANK INSPECTIONS

RAI 3.1.26-1:

The plant condensate storage tank inspections consist of a one-time inspection of the tanks' internal surfaces to verify the adequacy of the chemical control program. 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. Discuss why these locations were stated to be the most susceptible. Also, discuss how you will apply your inspection findings to other tank components.

RESPONSE TO RAI 3.1.26-1:

As stated in Section C.2.2.2.3 of the Plant Hatch LRA, the Unit 1 CST is fabricated from aluminum alloys (with galvanized steel flanges), and the Unit 2 CST is fabricated from stainless steel. These materials are not coated, and are resistant to general corrosion. Therefore, localized corrosion mechanisms such as pitting and crevice corrosion were determined to be the likely modes of age related degradation within these tanks.

Crevice corrosion occurs in creviced areas, such as those created when welding the standpipes to the standpipe supports, or at attachment nozzle connections or welds. The CST inspection will focus on creviced areas to assure no unacceptable indications of corrosion exist.

Additionally, SNC has determined that tank welds, and associated heat affected zones, are more likely to experience corrosion via pitting and crevice corrosion due to the welding process. The CST inspection includes a representative sample of these welded areas to assure no unacceptable indications of corrosion exist.

Significant corrosion is not expected due to environmental controls provided by the chemistry program, and the use of corrosion resistant materials. However, if unacceptable indications of corrosion are noted during the inspection, an engineering evaluation will be performed to identify what additional activities on the CSTs would be warranted.

RAI 3.1.26-2:

Table 3.2.4–5, "Components Supporting Condensate Transfer and Storage System," of the LRA, identifies loss of material for the aluminum, galvanized and stainless steel tanks in the demineralized water environment. The loss of material due to galvanic corrosion, crevice corrosion, pitting, and microbiologically influenced corrosion is discussed in Section C.2.2.2.3, "Aging Management Review for Condensate Storage Tanks," of the LRA, and credit for Condensate Storage Tank (CST) Inspections is taken as an AMP. The CST Inspections program includes a one-time visual inspection of internal surfaces to detect the loss of material. Provide the following:

a. Describe the acceptance criteria and methodology used to analyze the results of the inspection under the CST inspection program.

b. Visual inspections may not be sensitive enough to adequately assess the condition of the CSTs. Discuss why UT was not considered, in conjunction with the visual inspection, to adequately inspect the CSTs for corrosion.

c. Discuss examples of corrective actions taken if corrosion/damage is identified.

RESPONSE TO RAI 3.1.26-2:

See Appendix B, Section 3.4.

The visual examination procedures for the CST inspection, including lighting and resolution requirements, will be similar to the VT-1 provisions in ASME Code recommendations, and are capable of detecting unacceptable corrosion. Additional inspection methodologies, such as volumetric or surface examinations, were options considered by SNC. However, as presented in the response to RAI 3.1.26-1, localized corrosion due to pitting and crevice corrosion are expected to be the most likely modes of corrosion possible in the Plant Hatch CSTs, and even these mechanisms are not expected to be aggressive in the demineralized water environment. Cracking due to SCC or fatigue is not considered possible based on a review of the CSTs materials of construction and environment. Therefore, detailed visual inspections are adequate to detect localized corrosion. 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.

RAI 3.1.26-3:

Discuss how the results of the CST inspections will be used, especially with regard to the chemistry control programs.

RESPONSE TO RAI 3.1.26-3:

Demineralized water and condensate storage tank chemistry control is based on the guidance of EPRI TR 103515, "BWR Water Chemistry Guidelines," and on the achievable purity obtainable from the makeup demineralizer system. No corrosion inhibitors or biocides may effectively be added since the CST periodically supplies makeup to, and receives effluent from, the reactor coolant system. Therefore, while they are utilized to evaluate required corrective actions and the need for additional inspection requirements, the results of the CST inspection cannot be used to suggest modifications to the current chemistry regime, unless significant changes are made to reactor coolant chemistry control.

PASSIVE COMPONENTS INSPECTION ACTIVITIES

RAI-3.1.27-1:

Provide the following information regarding the Passive Component Inspection Activities AMP:

a. a description of the inspection population, frequency, and sample size including the bases for selection,

b. a description of, and the measuring technique for, the parameters to be monitored,

c. a description of the acceptance criteria and their bases, including a methodology for analyzing the inspection results against applicable acceptance criteria,

d. a description of how the detection of aging effects will occur before there is a loss of component intended function.

RESPONSE TO RAI-3.1.27-1:

PCIA is based on availability, not population. Thus, population, frequency, and sample size are not pre-determined. However, PCIA is coupled with a population-driven program (e.g., GSCI) to assure that in-scope components susceptible to aging effects that require management are inspected for age-related degradation. See Appendix B, Section 3.5.

RAI-3.1.27-2:

The Passive Component Inspection Activities is a new aging management activity at Hatch. These inspections will collect, report, and trend age-related data. This activity will verify the effectiveness of preventative or mitigative programs and activities credited for aging management. The program description seems generic enough to be applied everywhere at Hatch, not just for managing aging of carbon steel components exposed to a wetted gas environment (see Commodity Group C.2.2.9). Discuss the program and explain the unique features that limit its application to the aging management of carbon steel components exposed to a wetted gas environment when it appears as if it should be applied generically.

RESPONSE TO RAI-3.1.27-2:

See Appendix B, Section 3.5. This program was developed to address aging management of specific, in-scope components. SNC considered the application of PCIA to other, non-gas environments. However, SNC has chosen to use other, one-time inspections for those environments.

RHR HEAT EXCHANGER AUGMENTED INSPECTION AND TESTING PROGRAM

RAI 3.1.28-1:

In Section C.2.2.11 of the LRA, the applicant stated that visual inspections, eddy current, and leak testing would be used to monitor loss of material, loss of heat exchanger performance, and cracking. Provide a basis for the activities by correlating the inspections and testing to the aging effects they are intended to detect.

RESPONSE TO RAI 3.1.28-1:

See Appendix B, Section 3.6.

RAI 3.1.28-2:

The applicant provided in Section A.3.6 of the LRA, parameters that would be monitored or inspected. The parameters that can be inspected by visual inspection and eddy current testing are leakage, cracking, and loss of material. To determine the adequacy of using visual inspection and eddy current testing alone for monitoring and trending, provide a basis for not including flow, pressure, and temperature differences across the heat exchanger as parameters to identify reduction of cooling capacity due to fouling and/or loss of material.

RESPONSE TO RAI 3.1.28-2:

Because of uncertainties associated with monitoring and trending flow, pressure, and temperature difference, preventive maintenance activities with appropriate frequencies and acceptance criteria have been used to provide assurance that the heat exchangers will perform their intended heat transfer functions during the extended period of operation. The preventive maintenance activities include visual inspection, cleaning, eddy current testing, leak testing, and ISI. These activities and parameters inspected are described in the RHR heat exchanger augmented inspection and testing program, and the ISI program. See Appendix B, Sections 3.6 and 1.9.

RAI 3.1.28-3:

Discuss the bases for the techniques used to measure the parameters chosen for inspection and monitoring (e.g., EPRI guidelines, and ASTM procedures).

RESPONSE TO RAI 3.1.28-3:

See Appendix B, Section 3.6.

RAI 3.1.28-4:

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 applicant provided in Section A.3.6, of the LRA, the following inspection intervals for some of the components: 1) visual inspection of the heat exchanger partition plates every 54 months; 2) eddy current testing on the tubes at least once during each 10-year inspection interval or whenever leaks are suspected in tubes and/or the tube sheet; 3) visual inspection of the shell side of the tube sheets, shell internals and impingement plates once per 10-year inspection interval, where accessible; and leak testing of the tube and tube sheet leak testing whenever leaks are suspected.

To determine the adequacy of these frequencies for monitoring and trending, provide the aging effects which these inspections are intended to detect and the basis for the frequencies indicated.

RESPONSE TO RAI 3.1.28-4:

The aging effects that the subject inspections and testing detect are identified in Appendix B, Section 3.6.

The bases for the testing frequencies are as follows:

The inspection interval for partition plate is based on initial inspection results. The initial channel assembly inspection results were found satisfactory, and provided assurance that the equipment will perform its intended safety functions during the intervals between the inspections. Subsequent inspection was also found satisfactory.

The eddy current testing frequency is based on the 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 during the tests. Also, the heat exchanger total heat transfer surface area is oversized by a minimum of 5 percent excess tubing to provide sufficient operating margin in the event tubes must be plugged. The combination of satisfactory test results and overdesign of the heat exchanger provides assurance that the equipment will perform its intended safety functions during the intervals between inspections. However, interval periods may be decreased if an adverse trend is encountered. Industry report, SAND93-7070.UC-523, "Aging Management Guideline for Commercial Nuclear Power Plants - Heat Exchangers," recommends an inspection frequency of 10 years. In case a leak is suspected in the heat exchanger tubes/tube sheets, an eddy current test is performed immediately after the leak test.

The shell side water is less harsh than the tube side water, and therefore, will not require the same frequency of inspection as the tube side components. The frequency of inspection of the shell side of the tube sheets, shell internals, and impingement plates is based on plant experience, and recommendation provided in Industry report, SAND93-7070.UC-523, "Aging Management Guideline for Commercial Nuclear Power Plants-Heat Exchangers."

RAI 3.1.28-5:

Monitoring and trending provide important information about how a system is performing relative to acceptance criteria. Proactive monitoring and understanding of trending behavior may allow corrective actions to be taken prior to exceeding acceptance criteria. Tables C.2.2.11-1 through C.2.2.11-4 of the LRA state that the program provides for monitoring and trending of data concerning the RHR heat exchanger condition. Provide a discussion of how the parameters are monitored and trended over time.

RESPONSE TO RAI 3.1.28-5:

The aging management of the RHR heat exchangers is comprised of several programs. While this specific RAI is in the RHR heat exchanger program section, it seems to ask about aging management of the heat exchangers in general.

The following material condition monitoring and trending methods have been used in relation to heat exchanger performance:

- Visual inspection
- Eddy current testing
- ISI
- Pit inspection and diving (Now part of PSW and RHRSW inspection program)

Visual Inspection

The objective of the visual inspection is to monitor, at a prescribed frequency, the condition of the heat exchanger components in relation to heat transfer. This method assumes that the heat exchanger will perform its intended function if it is maintained in an acceptably clean condition. The parameters monitored during this inspection are loss of material, fouling (flow blockage) and cracking. Measured or recorded parameters are evaluated against acceptance criteria. Corrective actions, or additional inspections or adjustment of inspection frequency, are initiated based on the trend of the inspected parameters. This activity is part of the plant service water and RHR service water inspection program, and the RHR heat exchanger augmented inspection program. See Appendix B, Sections 1.13 and 3.6, and LRA Section C.2.2.11 for details of this activity.

Eddy Current Testing

Eddy current testing is a non-destructive examination method to monitor, at a prescribed frequency, the condition of heat exchanger tubing in relation to heat transfer. The parameters monitored during this inspection are loss of material, fouling, and cracking. All measured or recorded parameters are evaluated against acceptance criteria. Corrective actions, or additional inspections or adjustment of inspection frequency, are initiated based on the trend of the inspected parameters. This activity is part of the RHR heat exchanger augmented inspection and testing program. See Appendix B, Section 3.6, for details of this activity.

Inservice Inspection

Inservice inspection is a volumetric and surface examination to monitor, at a prescribed frequency, the condition of heat exchanger shell welds and shell base material in relation to heat transfer. The parameters monitored during this inspection are loss of material and cracking. All measured or recorded parameters are evaluated against acceptance criteria. Corrective actions, or additional inspections or adjustment of inspection frequency, are initiated based on the trend of the inspected parameters. This activity is part of the ISI program. See Appendix B, Section 1.9, for details of this activity.

Pit Diving and Inspection

The pit diving and inspection activities of the structural monitoring program are now part of the plant service water and RHR service water inspection program. The pit diving and inspection activities require that the intake structure pump suction pit be inspected every twelve months by divers, and any sedimentation removed. Removal of sedimentation will prevent the sedimentation from entering the system, and thereby, prevent or minimize flow blockage and loss of material. All measured or recorded parameters are evaluated against acceptance criteria. Corrective actions, or additional inspections or adjustment of inspection frequency, are initiated based on the trend of the inspected parameters. See Appendix B, Section 1.13, for details of these activities.

Therefore, the programs mentioned in Tables C.2.2.11-1 through C.2.2.11-4 monitor and trend the parameters in relation to heat transfer capability of the heat exchanger. Monitoring and trending these parameters, and implementing corrective actions based on test or inspection results, provide reasonable assurance that heat transfer capability of the heat exchangers will be maintained.

RAI 3.1.28-6:

Acceptance criteria is a necessary element to any AMP. The applicant states in Tables C.2.2.11-1 through C.2.2.11-4 of the LRA that the acceptance criteria for the RHR Heat Exchanger aging management is provided in the RHR Heat Exchanger Augmented Inspection and Testing Program. The applicant states in the RHR Heat Exchanger Augmented Inspection and Testing Program description in Section A.3.6 of the LRA that the acceptance criteria provided for this program will be contained in the inspection and testing procedure(s). Provide details of the acceptance criteria for the parameters that will be monitored.

RESPONSE TO RAI 3.1.28-6:

See Appendix B, Section 3.6.

RAI 3.1.28-7:

Operating experience provides the staff additional information about the acceptability of an AMP. The staff reviewed the AMR for RHR Heat Exchangers, provided in Section C.2.2.11.1, for the review of operating experience. Although the applicant described the operating experience for a five-year period under consideration, the applicant did not identify any corrective actions in the discussion. The discussion should be supplemented with this information in order to evaluate the adequacy of the new AMP.

RESPONSE TO RAI 3.1.28-7:

See Appendix B, Section 3.6.

TORUS SUBMERGED COMPONENTS INSPECTION PROGRAM

RAI 3.1.29-1:

Appendix A.3.7 of the LRA states that inspections will be conducted on accessible components submerged in suppression pool water, including the emergency core cooling system pump suction strainers and the reactor core isolation cooling pump suction strainer. The submerged portions of the safety relief valve and the vacuum relief piping are also included, as is the low carbon steel non-Class 1 piping. The staff cannot identify from the application the systems that contain the (1) emergency core cooling system pump suction strainers, the (2) submerged portion of the safety relief valve and the vacuum relief piping, and (3) the low carbon steel non-Class 1 piping. Please provide this information.

RESPONSE TO RAI 3.1.29-1:

A summary of the scope of the torus submerged components inspection program is provided in response to RAI 3.1.29-3.

RAI 3.1.29-2:

Appendix A.3.7 of the LRA states that inspections will be conducted on accessible components submerged in suppression pool water. Confirm that the results of such inspections will be used to determine the acceptability of inaccessible components as well as components not completely submerged in the suppression pool water. If so, discuss how the results of the inspections will be applied to all Hatch components exposed to the suppression pool water environment and provide examples with technical bases that will lead to a conclusion of acceptance.

RESPONSE TO RAI 3.1.29-2:

All components within the scope of the torus submerged components inspection program are accessible for inspection, if required. However, only a percentage of the components within the scope of the program will be examined during each inspection period. This sample set may also include inspection points located above the suppression pool water level for those locations deemed more susceptible to corrosion. Such areas would include those dissimilar metal welds and weld heat affected zones potentially in a "splash zone" above the suppression pool water level.

Results of past torus inspections have not detected significant corrosion of the components included in the program. In addition, suppression pool water chemistry is regularly monitored by the suppression pool chemistry control AMP to assure suppression pool water purity is maintained. Based on this data, significant corrosion of uncoated stainless steel and alloy steel components in the suppression pool is not expected under normal operating conditions. Therefore, a limited inspection program, focusing on the most likely corrosion locations, is adequate to manage aging, and selected inspection locations will bound potential corrosion occurring on uncoated components in the suppression pool. Locations include welds, weld heat affected zones, and crevice areas. If unacceptable corrosion is identified, an engineering evaluation of the inspection results will be performed to determine what corrective actions may be required, and whether additional inspections are warranted.

RAI 3.1.29-3:

Based on the tables in Section 3.2 of the application and the commodity group discussions, the staff considers the (1) high pressure coolant injection system, (2) the primary containment purge and inerting system, (3) the nuclear boiler system, (4) the residual heat removal system, (5) the core spray system, and (6) the reactor core isolation coolant system to be within the scope of the Torus Submerged Components Inspection Program. However, these systems are not clearly identified as being within the scope of this AMP in Appendix A.3.7 of the application. Clarify the scope of the Torus Submerged Components Inspection Program to resolve this inconsistency.

RESPONSE TO RAI 3.1.29-3:

Inspections accomplished in accordance with the torus submerged components inspection program include stainless steel and uncoated alloy steel components submerged in the suppression pool or in the vapor space immediately above the suppression pool water level. Specifically, the following components are included in the scope of the program:

1. Torus suction strainers for RHR (E11), Core Spray (E21), HPCI (E41), and RCIC (E51) systems are included in the program. These components are identified in Plant Hatch LRA Section C.2.2.3.2, and Tables 3.2.3-2, 3.2.3-3, 3.2.3-4, and 3.2.3-5.

2. HPCI and RCIC turbine exhaust headers are included in the program. These stainless steel piping components are identified in LRA Section C.2.2.3.2, and Tables 3.2.3-4, and 3.2.3-5.

3. SRV exhaust piping components are included in the program. These stainless steel piping components are part of the nuclear boiler system (B21), and are identified in LRA Section C.2.2.3.2 and Table 3.2.1-2.

4. The steel primary containment purge and inerting system (T48) vacuum relief piping components included in the program are identified in LRA Section C.2.2.3.1 and Table 3.2.3-7.

Components submerged in the suppression pool, but protected by inorganic zinc or epoxy coatings, such as downcomers and torus shell braces, are inspected as part of the protective coatings program, not the torus submerged components inspection program. However, torus submerged component inspection program and protective coatings program activities in the suppression pool are accomplished concurrently utilizing underwater inspection techniques.

RAI 3.1.29-4:

From the tables in Section 3.2 and the discussion in C.2.2.3 of the LRA, there appear to be four groups of programs to manage the aging effects of components exposed to the suppression pool water environment:

a. the Suppression Pool Chemistry Control and Torus Submerged Components Inspection Program for submerged carbon or stainless steel components;

b. the Suppression Pool Chemistry Control, Galvanic Susceptibility Inspections, and Treated Water Systems Piping Inspections for carbon steel components that are NOT submerged;

c. the Suppression Pool Chemistry Control and Treated Water Systems Piping Inspections for stainless steel components that are NOT submerged;

d. the Suppression Pool Chemistry Control and RHR Heat Exchanger Augmented Inspection and Testing Program for RHR shells and tube components, structural supports, vent pipe, vent header, and down-comers (the Inservice Inspection Program is also used for one particular RHR component).

Confirm that the first group listed above (submerged carbon or stainless steel components) will be covered by the Torus Submerged Components Inspection Program and that the other three groups listed above are not submerged but exposed to the suppression pool water environment.

RESPONSE TO RAI 3.1.29-4:

The response to RAI 3.1.29-5 includes a summary of the SNC approach to aging management of components exposed to a suppression pool environment.

RAI 3.1.29-5:

The Galvanic Susceptibility Inspection Program is cited for all non-submerged carbon steel components except for the carbon steel thermowell in the RHR system and the carbon steel pump casings in the core spray system. Also, the Galvanic Susceptibility Inspection Program is cited for submerged carbon steel piping in the primary containment purge and inerting system. This appears to be a discrepancy. In addition, the special inspections for the RHR system, which manage aging effects caused by exposure to the suppression pool water, are not discussed in C.2.2.3. The staff requests a clarification of your approach to managing aging effects for components exposed to the suppression pool water environment as well as clarification of the discrepancies noted above.

RESPONSE TO RAI 3.1.29-5:

The approach to managing aging effects for components exposed to a suppression pool water environment may be divided into three broad categories:

1. Components submerged in the suppression pool are age managed by suppression pool chemistry control and by the torus submerged components inspection program or the protective coatings program, depending on whether or not the component is coated.

2. Components outside the suppression pool that contain torus water are age managed by suppression pool chemistry control and applicable inspection programs, such as TWSPI and galvanic susceptibility inspections.

3. RHR system heat exchangers are subjected to multiple environments, including both torus water and raw water. The aging management philosophy for these components is specific in nature, and is therefore addressed separately in Section C.2.2.11.1 of the Plant Hatch LRA.

In response to the specific clarifications requested, the following information is provided:

- There are no dissimilar metal welds between the carbon steel RHR system thermowell or core spray pump casings and associated piping components. Thus, corrosion due to a galvanic couple is not possible, and the galvanic susceptibility inspection does not apply to these components. Note that Section C.2.2.3 of the Plant Hatch LRA presents all of the aging management programs applicable to that commodity. All of the aging management programs presented do not necessarily apply to all of the components included within the commodity. The Plant Hatch LRA Section 3 tables provide this component-specific information.

- For the primary containment purge and inerting piping system (T48) submerged carbon steel piping under consideration in LRA Table 3.2.3-7, the galvanic susceptibility inspection should not have been included.

RAI 3.1.29-6:

Visual inspections of specific carbon and stainless steel submerged components following the guidance for VT-1 inspections in ASME Section XI (IWA-2210), or another suitable method as dictated by the component configuration, are performed as part of the Torus Submerged Components Inspection Program. The staff finds VT-1 visual inspections to be adequate for identifying loss of material. However, the staff finds that VT-1 visual inspections are not sensitive enough for detecting stress corrosion cracking (SCC). According to section C.1.2.2.2 of the application, stainless steel components in the HPCI and RCIC turbine discharge headers inside the torus may be susceptible to SCC. For this type of defect, other nondestructive examination techniques are more appropriate (e.g., enhanced VT-1 visual inspection in accordance with BWRVIP-03). Provide additional information to justify your use of a VT-1 visual inspection for the aforementioned stainless steel components susceptible to SCC or, as an alternative, provide an acceptable alternative inspection technique.

RESPONSE TO RAI 3.1.29-6:

Although SNC has conservatively postulated that certain stainless steel components submerged in the suppression pool could experience SCC, austenitic stainless steel weld heat affected zones are realistically the only areas where significant cracking due to SCC could be possible. A review of industry operating experience, and Plant Hatch operating experience, did not reveal any instances of SCC of these components. Therefore, it is unlikely that any significant SCC will occur, during either the current term or the period of extended operation.

In addition, since the function of the stainless steel components of concern is to direct exhaust steam into the suppression pool, only advanced and extensive SCC would have an impact on this function. In the torus environment, significant cracking due to advanced SCC will be visible to the unaided eye, and is likely to be accompanied by pitting or significant rust discoloration.

Therefore, based on the above, VT-1 quality visual examinations were deemed sufficient to appropriately address the potential for degradation of austenitic stainless steel components in the suppression pool that are periodically exposed to HPCI or RCIC turbine exhaust steam. If inspection results or future operating experience indicate that additional inspection methods are warranted, SNC will consider alternative inspection techniques at that time.

RAI 3.1.29-7:

Discuss how IN 88-82, "Torus Shells with Corrosion and Degraded Coatings in BWR Containments," including IN 88-82, supplement 1, have been incorporated into the torus submerged components inspection program. The INs discuss how Mark I containment tori have experienced interior protective coating degradation problems (e.g., Nine Mile Point 1 torus), including sedimentation of coating material as debris covering the bottom portion of a torus that prevented adequate inspection by divers (unless divers are directed to look at the torus shell surface after removal of the debris). Provide details regarding how your underwater inspections are conducted to consider this operating experience. How does your inspection procedure provide adequate aging effects management of the bottom half of the torus shell, which may be covered by coating debris?

RESPONSE TO RAI 3.1.29-7:

Torus desludging, inspection, and coating operations are accomplished in accordance with the Plant Hatch protective coatings program. The Unit 1 and Unit 2 torus shells are periodically desludged utilizing diver operated filtration equipment. Results of past inspections indicate that only relatively minor buildup of sludge and sediment has occurred between inspections. Any debris not removed by the filtration process is removed manually by divers. Inspections of the torus immersion coatings do not proceed until the areas under consideration have been desludged and all significant debris removed.

After desludging is complete, coatings inspections of torus shell immersion areas are performed, including both qualitative and quantitative evaluations. Qualitative evaluations include a "swim through" of all torus bays to identify any areas of significant coating degradation or corrosion. Quantitative evaluations include removal of corrosion products from pit areas, measurement of pit depth utilizing depth gages, and selected measurements of existing coating thickness. Subsequent to evaluation, damaged areas are recoated, utilizing an underwater cured epoxy. Results of previous inspections are utilized to select sites for quantitative inspection. Inspection and desludging frequencies are based on the results of past inspections, and may be modified in the future as conditions change.

RAI 3.1.29-8:

Acceptance criteria are a necessary element to any AMP. The staff requests the applicant provide the acceptance criteria for the Torus Submerged Components Inspection Program.

RESPONSE TO RAI 3.1.29-8:

See Appendix B, Section 3.7.

RAI 3.1.29-9:

Discuss the industry experience or other inputs that led to the determination that regular, periodic inspections of the submerged components is required. That is, discuss how your plant-specific operating experience and/or your evaluation of the industry's operating experience led to the development of the Torus Submerged Components Inspection Program. Relate the operating experience discussed generically in the relevant commodity group (e.g., C.2.2.3) to the Torus Submerged Components Inspection Program and discuss why it is acceptable to delay implementation of this program until 2014 and 2018 for Hatch Units 1 and 2, respectively.

RESPONSE TO RAI 3.1.29-9:

SNC intends to conduct inspections of stainless steel and other uncoated components located in the torus concurrently with the protective coatings program inspections in the torus. Based on the results of past inspections (See Appendix B Section 3.7), and low predicted corrosion rates, SNC has concluded that the torus submerged component inspection program need not be implemented until the period of extended operation, and that the scope and frequency of additional inspections may be based on the inspection results obtained in baseline examinations. The infrequent inspections of uncoated stainless and alloy steel components accomplished by the torus submerged components inspection program should not be confused with the regular inspections of carbon steel components and associated coatings accomplished by the protective coatings program.

RAI 3.1.29-10:

Section 4.2.4 of the LRA addresses fatigue (both dynamic and thermal) of the torus structure and concludes that the critical event leading to fatigue of the torus is the lifting of one or more of the main steam system safety relief valves (SRV). The AMP "Component Cyclic or Transient Limit Program," discussed in Section A.1.12 of the LRA, shows the fatigue CUF calculated for the limiting location for the torus structure on each unit. It is not clear whether the "Component Cyclic or Transient Limit Program" AMP covers the torus submerged components. Clarify this and discuss in detail how the torus submerged components and their supports will be managed for aging effects such as possible vibration cracking, bolt-loosening associated with dynamic fatigue due to SRV loading, the pressure and thermal transients within the torus pool environment, and other dynamic effects (e.g., seismic loading).

RESPONSE TO RAI 3.1.29-10:

The CCTLP does not address fatigue of torus submerged components, except for those components that are part of the vent header system as defined in the PUAR. Torus submerged components were designed and installed in accordance with applicable codes that account for SRV lifts, pressure and thermal transients within the torus environment, and seismic loading to the extent required.

Fatigue of the Mark 1 vent header system was considered for the PUAR. These fatigue analyses do consider both oscillating pressure, thermal loads, and associated accident and seismic loads. The load combinations are addressed in detail in a February 28, 1983 submittal to the NRC of the PUAR and later changes are addressed in the June 2, 1983 submittal. The CCTLP monitors the CUF of the torus shell, which has been shown to be bounding for all torus components that were evaluated for fatigue by the PUAR. Class 2 and Class 3 components, other than those evaluated in the PUAR, did not require and have not had a detailed fatigue analysis performed. See Section 4.2.3 of the Plant Hatch LRA, and the response to RAI 3.1.29-12, for additional information.

As an aging mechanism leading to loss of preload in piping connections and closures, vibration manifests itself early in the operation of a bolted closure after the bolts are torqued. The amount of preload prescribed for a bolted connection includes a vibration component. The torque activities AMP provides for procedural controls to assure the proper amount of preload is applied.

Bolted structural connections in the torus are not subject to high temperatures, high displacement vibration loading, or high stress vibration loading. No gaskets are used in structural connections. Bolts and anchors in the primary containment vessels and structures inside containment were installed and inspected per plant procedures in accordance with AISC requirements. For structural joints installed with proper torque, the initial loss of preload is limited, and sufficient preload remains to assure joint integrity. Per the 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. Past inspections have not noted any cases of loss of preload in bolted structural joints. Therefore, loss of preload due to self-loosening of bolts is not considered an aging effect requiring management.

RAI 3.1.29-11:

Table 3.2.1-2, which lists the components that support the Nuclear Boiler System, does not include two non-Class I piping items in the torus water environment that are covered by commodity groups C.2.2.3.1 and C.2.2.3.2. These two commodity groups employ the Suppression Pool Chemistry Control and the Torus Submerged Components Inspection Program AMPs. Are there portions of the SRV piping that are submerged in the torus water? If so, Identify these submerged components.

RESPONSE TO RAI 3.1.29-11:

As stated in the response to RAI 3.1.29-1, the SRV tailpipes are stainless steel below the suppression pool water level, and hence, are included in LRA Section C.2.2.3.2. The section C.2.2.3.1 reference to the nuclear boiler system (B21) is an editorial error in the LRA.

RAI 3.1.29-12:

Lifting of one or more of the SRVs could lead to vibratory fatigue of the torus shell and submerged components. Discuss why thermal fatigue but not vibratory fatigue is discussed as a potential aging effect for carbon steel and stainless steel components (e.g., Section C.1.2.2.2).

RESPONSE TO RAI 3.1.29-12:

The CCTLP, as described in Appendix B, Section 1.12, accounts for fatigue due to SRV lifts for the torus shell and those torus submerged components included in the torus fatigue analysis. See the response to RAI 3.1.29-10 for additional information.

Fatigue of piping components and associated supports installed in the torus due to thermal cycling is considered in LRA Sections C.2.2.3.1, C.2.2.3.2, and C.1.2.2.2. These components, and associated supports, were designed and installed in accordance with USAS B31.7 Classes 2 and 3 (Unit 1), and ASME Section III Classes 2 and 3 (Unit 2). SNC evaluations conclude that these components will remain bounded by current design basis analyses through the period of extended operation.
Section 4.2.3 of the LRA provides a discussion of the evaluation and analysis utilized to assure that design analyses for fatigue of non Class 1 piping remain valid in the extended operating period.

RAI 3.1.29-13:

The application considered aging effects due to the lifting of SRVs during plant operation. The staff notes that following the lift of an SRV, steam enters the SRV discharge line, compressing the air within the line and expelling the water into the suppression pool. The steam and compressed air enters the pool in the form of high pressure bubbles. The oscillating bubbles result in a dynamic loading on the nearby submerged structures including the torus shell. This would cause the removal of protective corrosion films, coatings and the base metal as a result of the highly localized stress produced in the metal surface due to the impingement and the collapse of the vapor bubbles. However, the application does not address the aging effects associated with the suppression pool short term dynamic loading. Please discuss in detail how this aging effect can be managed. Identify AMPs that are applicable to, and systems that are affected by, the aging effects associated with the suppression pool dynamic loadings mentioned above.

RESPONSE TO RAI 3.1.29-13:

A review of the results from past Plant Hatch torus immersion coating inspections concludes that indications of this phenomenon have not been observed at Plant Hatch. In addition, the physical layout of safety relief valve discharge lines assure that steam discharge from safety relief valves does not directly impinge on the torus shell or internal supports. Therefore, SNC does not consider this phenomenon to be a plausible aging mechanism.

However, if degradation of the torus due to this postulated phenomenon were to occur, the protective coatings program is adequate to detect any significant degradation in a timely manner, and to provide for appropriate corrective actions.

V. TLAA AND SSC-RELATED RAI RESPONSES

ELECTRICAL

RAI 2.5-ELEC-1:

Sections 3.4.1, C.1.3, and C.2.5 of the LRA evaluate the aging effects, applicable to electrical components, that are expected to occur due to (1) thermal degradation of organic materials, (2) thermoxidative degradation, (3) radiolysis of organic materials, and (4) water treeing, depending on environmental conditions. Further, the LRA states that high temperatures can result in thermal degradation and thermoxidative degradation of electrical components and that a radiation environment can result in radiolysis of organic materials. However, the LRA concludes that no aging effects associated with high temperature or radiation require aging management for non-EQ (environmental qualification) cables, connectors, splices, and terminal blocks. This conclusion is not consistent with the aging management programs and activities for electrical cables and connections exposed to adverse localized environments caused by heat or radiation as described in the staff's Generic Aging Lessons Learned Report and the two previous license renewal applications that have been approved by NRC. Therefore, for non-EQ cables, connectors, splices, and terminal blocks that are within the scope of license renewal and located in the reactor building, control building, the lower regions of the drywell, the turbine building, the diesel generator building and the intake structure, provide a description of the following:

- An aging management program for accessible and inaccessible electrical cables and connections 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.

RESPONSE TO RAI 2.5-ELEC-1:

SNC recognizes that industry information exists regarding the effects of temperature and radiation on electrical cables. SNC is also aware of the GALL report information, and has followed NRC and applicant discussions on this subject during the first two license renewal reviews.

However, for Plant Hatch, the evaluation of non-EQ cables determined that each cable type was capable of performing its function for the entire plant life, including the renewal term. The evaluation was based on actual plant temperatures and radiation levels. Conservative temperatures, based on design temperatures supplemented by walkdowns, and actual temperature measurements have been established for each plant area containing electrical cables within the scope of license renewal. These temperatures have been compared to the temperatures each cable type is capable of withstanding for a 60-year life. All in scope cable types are capable of withstanding the temperatures and radiation levels to which they will be exposed in the plant for the full 60-year period.

SNC has performed thermal surveys, and has found no localized hot spots that might be detrimental to in scope cables. Occurrences of degraded cable are identified and dispositioned routinely through the corrective actions and maintenance programs.

Plant Hatch operating experience has borne out the observations made in the preceding paragraph. SNC has conducted inspections of EQ cables inside containment at Plant Hatch for a number of years. These inspections, which originated after the issuance of Information Notices 92-81 and 93-33, involve visual examination of exposed sections of cables in areas where the temperatures exceed the time and temperature value suggested in Information Notice 92-81, and have been used to supplement the aging evaluations for cables in the EQ program. The inspections have been conducted both inside the drywell and in the top of the steam chase outside containment. The inspections have, historically, been conducted every outage, although recently the interval has been increased to every other outage based on inspection results.

Based on the absence of localized hot spots in areas where in scope, non-EQ cables are present, inspection of these non-EQ cables in other areas outside containment would be of little value, since temperatures are not high enough to be of concern. Based on the factors presented above, SNC concludes that the existing EQ activities conservatively bound the non-EQ cables and connectors, both inside and outside the drywell. Deficiencies discovered as a result of EQ activities will continue to be dispositioned as before, with cables and connectors replaced as necessary.

REACTOR AND REACTOR COOLANT SYSTEM

RAI 3.2.3.1-1:

To determine whether the applicant has identified all applicable aging effects for the reactor assembly system, nuclear boiler system and recirculation system, the applicant is requested to provide the following:

a. The industry experience related to the aging effects for components in the reactor assembly system, nuclear boiler system, and reactor recirculation system (Hatch experience is identified, but industry experience is not identified). How does industry experience impact the aging effects and aging management program for these components?

b. According to Table 3.2.1-1, all components in the reactor assembly system, except for the shell and closure head, are subject to cracking. Closure studs and nozzles are part of the same commodity group as the shell and closure head and these components list cracking as an aging effect. Provide your basis for excluding cracking as an aging effect for these components.

c. According to Table 3.2.1-2, all components in the nuclear boiler system, except for the bolting, are subject to cracking. Provide your basis for excluding cracking as an aging effect for these materials.

d. Bolting (non-Class 1) in the nuclear boiler system and bolting in the reactor recirculation system are subject to loss of preload and loss of material. Bolting (Class 1) in the nuclear boiler system is identified as not being subject to loss of material and closure studs in the reactor assembly system are identified as not subject to loss of material or loss of preload. Explain why some bolting is subject to loss of preload and loss of material and some are not.

e. Many of the commodity groups associated with the nuclear boiling system and the recirculation system are subject to loss of material. Although the nuclear boiler system, recirculation system and reactor assembly system are in a reactor water environment, the commodity groups in the reactor assembly system are not subject to loss of material. Explain why the materials in the reactor assembly system are not subject to loss of material and materials in the nuclear boiling system and recirculation system are subject to loss of material.

RESPONSE TO RAI 3.2.3.1-1:

a. Page 3.0.6 of the Plant Hatch LRA contains a summary of the types of documents reviewed in preparing the application. This paragraph is reproduced below:

"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 walk downs, interviews, and records searches."

The methodologies employed to prepare Plant Hatch AMRs assured that aging effects noted in these communications were appropriately considered in the Plant Hatch LRA. A list of generic communications considered is provided in LRA Appendix C, Section C.1.5.

Regarding reactor assembly components, BWRVIP relied on extensive review of applicable industry operating experiences and examination results to develop appropriate inspection and evaluation guidelines. SNC has evaluated the BWRVIP for its applicability to Units 1 and 2 design, construction, and operating experience, and concluded that the BWRVIP reports bound Units 1 and 2 design and operation.

For nuclear boiler and reactor recirculation system components, existing programs credited to manage the effects of aging are based on established industry codes, standards, and guidelines. Therefore, applicable industry experience relating to these components is considered in establishing appropriate inspection methodologies and acceptance criteria contained in credited programs and activities.

See the Appendix B AMP descriptions for reference to specific applicable industry codes, standards, and guidelines on which program methodologies and acceptance criteria are based.

b. The RPV closure head and RPV shells evaluations were documented in BWRVIP-05, BWRVIP-60, and BWRVIP-74. LRA Table C.2.1.1-1 incorporates BWRVIP-74 by reference. BWRVIP-74 references BWRVIP-05 and BWRVIP-60, which have been approved by the NRC staff. BWRVIP-74 is currently under review by the NRC staff. SNC has established that the BWRVIP reports bound the Units 1 and 2 design and operation, and that the applicable portions of BWRVIP reports will be implemented at Plant Hatch as documented in the final NRC Safety Evaluation Reports, except where specific exception has been identified to the NRC.

For the RPV closure head and RPV shells, these BWRVIP documents conclude that loss of fracture toughness due neutron embrittlement of the beltline shells is the only significant aging effect requiring aging management during the period of extended operation.

Cracking of the vessel shell and closure head due to fatigue and SCC was determined not to be an aging effect requiring management by BWRVIP-74. 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 and BWRVIP-60 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.

c. AMRs considered SCC and fatigue as potential mechanisms contributing to cracking of fasteners in the nuclear boiler system. However, those AMRs concluded that neither SCC nor fatigue of fasteners were aging effects requiring management. A summary of the evaluation is provided below.

Stress Corrosion Cracking:

- 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, which 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 has 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 stress corrosion crack initiation and propagation.
- Plant Hatch has implemented procedural processes to minimize the potential for excessive applied stresses due to improper preload.

Fatigue:

Cracking due to fatigue is not considered 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.

d. RPV closure studs are evaluated by BWRVIP-74. This document concluded that loss of preload and loss of material are not aging effects requiring management for RPV closure studs. LRA Table C.2.1.1-1 incorporates this document by reference.

SNC determined that steel fasteners within the Class 1 boundary, excluding fasteners associated with the RPV, could experience loss of preload since no analysis was available to exclude this aging effect. However, all fasteners within the Class 1 boundary are fabricated from low alloy steels such as SA540, Gr. B23 or SA193, Gr. 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 concluded to be 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. SNC 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.

e. Evaluations performed with regard to vessel components utilized BWRVIP reports that are based on extensive research, testing, and industry experience. In addition, applicable BWRVIP inspection and evaluation documents have been submitted to the NRC for approval, and are incorporated by reference into the Plant Hatch LRA, Tables C.2.1.1-1 and C.2.1.1-5. This additional data, made available through BWRVIP documents, allows for a different determination concerning the potential for corrosion in reactor assembly components from the determination conservatively applied to other Class 1 components not addressed by the BWRVIP documents. Therefore, for the reactor assembly components under consideration, loss of material is not considered an aging effect requiring management based on applicable BWRVIP inspection and evaluation guidelines.

While loss of material due to corrosion is expected to be unlikely for any Class 1 component, and possible corrosion sites are limited to crevice areas or areas of stagnant flow, no plant-specific data is available to conclude that loss of material due to corrosion is not an aging effect requiring management. Thus, TWSPI and the ISI program are credited to verify that no significant loss of material is occurring in nuclear boiler system or reactor recirculation system components. These inspections serve to validate the effectiveness of reactor water chemistry control.

RAI 3.2.3.1-2:

Void Swelling is not identified as an aging effect for any component in the reactor assembly system. The impact of change of dimension due to void swelling on the ability of the reactor vessel internals to perform their intended functions is of concern to the staff and has been addressed in previous applications. EPRI TR-107521, "Generic License Renewal Technical Issues Summary," EPRI, April 1998, cites several sources with conflicting results. One source predicts swelling as great as 14% for PWR baffle-former assemblies over a 40-year plant lifetime, whereas results from another source indicate that swelling would be less than 3% for the most highly irradiated sections of the internals at 60 years. Provide the peak neutron fluence for the reactor internals at the end of the license renewal term. Based on this neutron fluence provide data that indicates void swelling is not an aging effect during the license renewal term. If it is an aging effect, identify the aging management program that will ensure the function of the internals is not degraded (result in cracking or change in critical dimensions) during the license renewal term.

RESPONSE TO RAI 3.2.3.1-2:

Void Swelling is not an aging effect. Rather, it is an aging mechanism, and the effects of concern would be swelling or cracking. The referenced discussion addresses data gathered from Liquid-Metal-Cooled Fast Breeder Reactors (LMFBRS), and how it may possibly be related to a PWR component (baffle-former bolt) that is in almost direct contact with the fuel in a PWR. A BWR does not have components located in a similar location, and thus, can reasonably be expected to experience less fluence. Secondly, the EPRI report notes that field experience does not support void swelling being a significant issue. The lowest temperature for which this phenomenon is conjectured to occur is 300°C (572°F), which is higher than the internals that either Plant Hatch unit will experience. Further, the BWRVIP Program for BWR internals addressed the key aspects of the internals components and provided inspection criteria where appropriate to manage aging. The BWRVIP Program that is being implemented at Plant Hatch is adequate to address aging of the internals.

RAI 3.2.3.2-1:

Cast austenitic stainless steel (CASS) components in the reactor assembly system and nuclear boiling system may be subject to loss of fracture toughness due to the synergistic effects of thermal and neutron embrittlement. CASS components are susceptible to thermal embrittlement if they operate at temperatures greater than 550 ^{O}F. Appendix H to 10 CFR Part 50 indicates neutron irradiation embrittlement becomes significant at neutron fluences greater than 10^{17} n/cm^2 (E>1Mev). Identify all CASS components in the reactor assembly system and nuclear boiler system that operate at temperatures greater than 550 ^{O}F and with neutron fluence greater than 10^{17} n/cm^2 (E >1MeV). What are the aging management programs for these components that will ensure cracks in these components will not exceed the critical size resulting from the loss of fracture toughness due to the synergistic effects of thermal and neutron embrittlement?

RESPONSE TO RAI 3.2.3.2-1:

There are no CASS components in the nuclear boiler system outside the vessel that experience the combination of 550°F and fluence greater than 10^{17} n/cm^2. Therefore, there is no AMP needed to deal with the effect of cracking caused by the synergistic effect of thermal and neutron embrittlement.

Although CASS material in portions of the jet pump assemblies may experience fluence greater than 10^{17} n/cm^2, these components will not experience temperatures exceeding 550°F. Aging management for all in scope components in the reactor vessel, including CASS components, is provided by the BWRVIP program. The inspections required by that program provide adequate aging management for cracking, regardless of the mechanism.

RAI 3.2.3.2-2:

The industry position on CASS is described in the Electric Power Research Institute report EPRI TR-106092, "Evaluation of Thermal Aging Embrittlement for Cast Austenitic Stainless Steel Components in LWR Reactor Coolant Systems," 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 review of this report is documented in a letter from C. I. Grimes (NRC) to D. J. Walters (NEI) dated May 19, 2000. This letter contains an enclosure that establishes the NRC position for inspection and analysis of CASS components.

Will all CASS components satisfy the inspection and analysis requirements specified in the enclosure to the May 19, 2000 letter. What is the proposed aging management program for components that do not satisfy the thermal embrittlement criteria and cannot demonstrate adequate flaw tolerance?

RESPONSE TO RAI 3.2.3.2-2:

The CASS components outside the reactor vessel are pump casings, valve bodies, and the main steam flow restrictor 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, SNC 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 C. I. Grimes to D. J. Walters letter of May 19, 2000. Note that the August 2000 version of GALL indicates that screening the pump casings and valve bodies for susceptibility to thermal aging is not required.

The reactor internals aging, including CASS components, is managed by the BWRVIP program (see the response to RAI 3.2.3.2-1).

RAI 3.2.3.2-3:

Section C.2.1.2 of the LRA indicates irradiation assisted stress corrosion cracking occurs in stainless steel as a result of a neutron fluence exceeding 3-5 x 10^{20} n/cm^2 (E>1.0Mev) and that only a small set of near-core internals exceed the neutron fluence threshold at Hatch during the license renewal term.

a. Identify the components that exceed the neutron fluence threshold criteria. What is the peak neutron fluence at the end of the license renewal term for components that exceed the neutron fluence threshold criteria? What aging management programs are proposed for the components that exceed the neutron fluence threshold criteria?

b. What inservice examination and frequency are required to preclude cracks from exceeding their critical size during the license renewal term? Provide a fracture mechanics analysis to demonstrate that the inservice examination and frequency will be adequate for detecting critical size flaws during the license renewal term, including the effects of neutron irradiation embrittlement on the fracture toughness.

RESPONSE TO RAI 3.2.3.2-3:

It is assumed that the intended reference is Section C.1.2.1.2 of the LRA, since there is no Section C.2.1.2.

The peak neutron fluence at the end of life has not been calculated for all the Plant Hatch internal components. However, as noted in Appendix E of the LRA, the peak fluence at the inner surface of the reactor vessel wall at 54 EFPY is predicted to be 3.47×10^{18} and 3.82×10^{18} n/cm^2 for Units 1 and 2, respectively. Based on these predicted fluences, and the relative location of reactor vessel internal components to the core, it is predicted that the components subject to AMR that might reach, or exceed, this threshold for IASCC are portions of the shroud and the top guide. Each of these components is covered by the BWRVIP program, which manages the aging effect of cracking, regardless of cause. The August 2000 proposed GALL report is consistent with this position.

RAI 3.2.3.2-4:

For all components that the staff has identified as being within the scope of license renewal (i.e. vessel flange leak detection line), provide Hatch and industry experience with age-related degradation. Identify the aging management program for these components that will ensure that their function is not degraded during the license renewal term.

RESPONSE TO RAI 3.2.3.2-4:

See the response to RAI 2.3.2-NBS-2. That response provided AMP information for the main steam line flow restrictors and venturi. Other than the items addressed in that RAI response, SNC is not aware of any nuclear boiler system or reactor coolant system components identified by the staff as being within the scope of license renewal that were not identified as in scope in the LRA. In scope structures and components subject to AMR (passive and long-lived) are identified and listed in Section 2, and AMRs and AMPs are presented in Appendices C.2 and A. Plant Hatch-specific operating experience is provided in the LRA for each commodity group in Section C.2. The results of industry operating experience reviews are summarized into the aging effects discussions in Section C.1. A list of the references used in generating this summary is contained in Appendix C, Section C.1.5.

RAI 3.2.3.2-5:

Operating experience in commodity group C.2.2.1.1 indicates that several failures have been observed of piping components downstream of orifices or other pressure reduction devices within steam systems. In all cases the cause of the failure was attributed to erosion corrosion related to pressure fluctuations within the system. The applicant indicates that this experience validates the conclusion that erosion corrosion can occur in areas not identified by the FAC model.

a. Has the amount of thinning of ASME Code class 1, 2, or 3 piping been predicted by your FAC model? If so, what rate has been used in the analyses and what was the acceptance criteria? Also, how are the FAC rates predicted and how are they adjusted based on the inspection results. Identify the implementing document for your FAC program for safety systems.
b. Identify locations in the steam system that were not predicted by the model as being susceptible to FAC, but had significant reduction in wall thinning. Based on these experiences, how has the FAC model for predicting the locations most

susceptible to FAC been changed? To ensure the FAC model accurately predicts the FAC rate and most susceptible locations during the license renewal term, will the FAC model be updated based on experiences during the initial operating period (40 years) and the license renewal term?

RESPONSE TO RAI 3.2.3.2-5:

This response first provides a clarification of the FAC program. The program manages the wall thinning phenomenon of flow accelerated corrosion for piping and components whose failure could result in injuries to personnel or which could result in detrimental operational effects. However, the FAC model can only predict the aging mechanism of FAC in large bore components, and it can only predict FAC if conditions such as service hours, flow rates, temperature, steam quality, fluid chemistry, and geometry are known. Therefore, the FAC program contains both modeled and non-modeled components, but the scope of the FAC program is limited to those high-energy systems determined to be susceptible to FAC.

Other mechanisms such as steam impingement, erosion, and erosion-corrosion are differentiated from FAC, and cannot be modeled. Thus, aging effects due to other wall thinning aging mechanisms are managed using industry and plant experience, engineering judgement, and trended inspections. In systems not susceptible to FAC, the TWSPI will manage aging effects due to aging mechanisms such as erosion-corrosion, cavitation and impingement.

a. Within the ASME Class 1, 2, or 3 boundaries, only the B21 system is modeled by the FAC program. The model initially predicts the relative ranking of components within a line segment with similar thermo-hydraulic and chemistry properties. The model then uses inspection data to refine predictions to the point where wear rates can be established. The model predicts very little FAC wear in this system, and its non-safety counterpart, N21. This has been verified by inspection data from both systems.

b. The model does not predict FAC susceptibility. Specific guidance (NSAC 202L) determines if a line segment in a system is susceptible to FAC. When a line is determined to be susceptible, a determination is made if the line can be modeled.

   The only steam lines in the scope of license renewal that have experienced significant reduction in wall thinning and were not modeled are the HPCI and RCIC steam line drains, as discussed in LRA Section C.2.2.1.1. These lines were not modeled since they are less than two inches. In-scope piping that is two inches or less is excluded from the computer modeling process since the program does not have the capability to model small bore piping. For small bore piping, the examination method and frequencies for the enhanced FAC program are based on industry and plant specific operating experience. Corrective actions to replace degraded sections of piping with FAC resistant material have been accomplished per the FAC program.

   The FAC model is periodically updated to incorporate the latest data obtained during refueling outages, and includes changes in chemistry, system configuration, or materials of construction.

RAI 3.2.3.2-6:

The BWR closure studs are exposed to reactor water and a humid environment and have had stress corrosion cracking (i.e. Dresden). Studs that are removed are required by Section XI of the ASME Code to have surface examination, and studs that are not removed are required by Section XI of the ASME Code to have end-shot ultrasonic examination. Have these examinations identified the loss of material or stress corrosion cracking for the Hatch studs? What is the aging management program for these studs and how do industry experience and the results from the Section XI examinations impact their aging management program?

RESPONSE TO RAI 3.2.3.2-6:

Industry experience concerning cracking of BWR reactor pressure vessel (RPV) closure studs was presented by GE communications to BWRs. Plant Hatch has reviewed these communications, implemented the recommendations concerning assessment and inspection of closure studs, and concluded that SCC of these studs is not an aging effect requiring management. This conclusion is based on a plant-specific evaluation of the closure studs and the vessel flange configuration. Additionally, inspections of closure studs installed at Plant Hatch have not identified any indications.

RPV closure studs are evaluated by BWRVIP-74, which determined that inspections conducted in accordance with Table IWB-2500 of ASME Section XI, as implemented by the ISI program, are appropriate to assure that cracking due to fatigue does not compromise closure stud component function.

RAI 3.2.3.2-7:

GL 88-01, "NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) in BWR Austenitic Stainless Steel Piping," and NUREG-0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," Revision 2 apply to all reactor coolant pressure boundary welds with piping connections 4 inches in diameter and larger, fabricated using austenitic stainless steel or nickel base alloys (Alloy 600 or Alloy 182) and carrying primary water at temperatures above 200 °F. The Reactor Pressure Vessel Monitoring program is identified as the aging management program for the stainless steel and nickel base alloy penetrations in the reactor assembly system. This program references BWRVIP-74, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," which indicates NUREG-0313 applies to safe-end welds. Will the penetrations in the reactor assembly system be inspected to NUREG-0313?

Other systems, such as some of the ECCS systems and the reactor water clean-up system, are in part ASME Code Class 1 and are part of the reactor coolant system. Are any of these systems made of austenitic stainless steel, alloy 600 or welded with alloy 182 wire? Within which systems and commodity groups are they evaluated? Provide a list of systems covered under the scope of GL 88-01. Also, provide a list of all reactor coolant pressure boundary austenitic and nickel base alloy components that operate above 200 °F. Will all of these components be inspected to NUREG-0313?

RESPONSE TO RAI 3.2.3.2-7:

In addition to this response, see the response to RAI 3.1.9-4. The scope of GL 88-01 has been correctly identified. Plant Hatch has performed, and will continue to perform piping and safe end examinations in accordance with GL 88-01 or NRC approved alternatives such as BWRVIP-75. The NRC issued an SER for BWRVIP-75 September 15, 2000. NRC is currently reviewing a request for technical alternative for SNC to use BWRVIP-75. The GL 88-01 examinations are part of the ISI program as noted in Section A.1.9 of the LRA. The August 2000 GALL position is consistent with this position.

Section 2.3.1.2 of the LRA (pages 2.3-5 and 2.3-6) describes the reactor coolant pressure boundary integrity (B21-02) function. Several "pressure containing systems" are included in the B21-02 function since the B21 function as presented in the LRA encompasses all Class 1 components (except B31 - reactor recirculation and B11 – reactor assembly components), regardless of MPL. Thus, all Class 1 components are within evaluation boundaries for B11, B21 and B31 intended functions, even if the component MPL designator is not B11, B21 or B31.

Class 1 stainless steel piping is evaluated in commodity group C.2.1.1.4. As described in LRA sections 2.3.1.2 and C.2.1.1.4, the list of systems covered under the scope of GL 88-01 includes only B21 and B31.

Section C.2.1.1.4 of the LRA provides a list of the reactor coolant pressure boundary components fabricated from austenitic stainless steels and nickel base alloys that operate above 200 °F.

Only BWR piping made of austenitic stainless steel, and safe ends with dissimilar metal welds that are four inches or larger in nominal diameter and contain reactor coolant at a temperature above 200°F during power operation will be inspected to GL 88 -01 requirements. Class 1 austenitic and nickel base alloy components outside the scope of GL 88-01 will be inspected in accordance with the ISI program.

RAI 3.2.3.2-8:

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.

Identify any ASME Code Class 1 small bore (nominal pipe size less than 4 inches) piping that could be subject to cracking from thermal fatigue, vibratory fatigue, or stress corrosion aging mechanisms. For each of these systems, provide your basis for concluding that these systems are subject or not subject to these aging effects. Identify the aging management program that can be used to determine whether cracking has occurred in these components. Identify the nominal pipe size and type of material used in the fabrication of the piping.

RESPONSE TO RAI 3.2.3.2-8:

The following systems contain ASME Code Class 1 small-bore (nominal pipe size less than four inches) piping that could be subject to cracking from thermal fatigue or stress corrosion aging mechanisms:

B21 - Nuclear Boiler
B31 – Reactor Recirculation
C41 – Standby Liquid Control
E11 – Residual Heat Removal
E21 – Core Spray
E41 – High Pressure Coolant Injection
E51 – Reactor Core Isolation Cooling
G31 – Reactor Water Cleanup

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 to manage aging of these components due to thermal fatigue is the CCTLP. Class 1 piping one inch and smaller was analyzed to ASME Class 2 methods. For the one inch and under size, cracking due to thermal fatigue is addressed as a TLAA in LRA Section 4.2.3. Section 4.2.3 provides the demonstration that the analyses remain valid through 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, 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), and
2. The components must be subject to residual tensile stresses of sufficient magnitude, and
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, SNC defines the corrosive environment as high temperature water where the ECP 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 IGSCC in the above systems, SNC has credited reactor water chemistry control, coupled with either the ISI program (for two inch and larger piping in these systems) or the TWSPI (for piping in these systems that is not included in the ISI program).

ESF SYSTEMS

RAI 3.3-CS-1:

Based on Table 3.2.3-3 of the license renewal application (LRA), Galvanic Susceptibility Inspections is an applicable aging management program (AMP) for the carbon steel piping and valve bodies exposed to the torus water environment. However, this AMP is not credited for managing the aging effects of the carbon steel pump casings exposed to the same environment. Resolve this inconsistency.

RESPONSE TO RAI 3.3-CS-1:

A review of the design documents for the core spray pumps revealed that the pumps' casings are not connected to any dissimilar metal. Thus, no galvanic couple exists, and the need for the galvanic inspection program is not applicable to these pumps, unlike the piping and valves of the system. The carbon steel piping and valve bodies are connected to stainless steel components such as orifice plates, instrument tubing, and ECCS strainers, thus requiring the galvanic inspection program be credited.

RAI 3.3-HPCI-1:

Based on Table 3.2.3-4 of the LRA, carbon steel piping exposed to reactor water is a non-class 1 commodity discussed further in Section C.2.2.1.1 of the LRA. This section describes the Treated Water Systems Piping Inspections as a method of validating the adequacy of the Reactor Water Chemistry Control. However, this program is not listed in Table 3.2.3-4 of the LRA as an applicable AMP for carbon steel components exposed to reactor water. Resolve this discrepancy.

RESPONSE TO RAI 3.3-HPCI-1:

As noted in electronic communication to NRC on April 19, 2000, for carbon steel piping exposed to reactor water in LRA Table 3.2.3-4, TWSPI was inadvertently omitted.

RAI 3.3-HPCI-2:

Based on Table 3.2.3-4 of the LRA, carbon steel piping exposed to demineralized water is a non-class 1 commodity discussed further in Section C.2.2.2.1 of the LRA. This section credits the Galvanic Susceptibility Inspections for providing appropriate examinations to identify potential loss of material due to galvanic corrosion. However, this program is not listed in Table 3.2.3-4 of the LRA as an applicable AMP for carbon steel piping exposed to demineralized water. Resolve this discrepancy.

RESPONSE TO RAI 3.3-HPCI-2:

For the carbon steel piping under consideration in LRA Table 3.2.3-4, the galvanic susceptibility inspection was inadvertently omitted from the table.

RAI 3.3-HPCI-3:

Based on Table 3.2.3-4 of the LRA, stainless steel piping exposed to a wetted gas environment is a non-class 1 commodity discussed further in Section C.2.2.9.2 of the LRA. This section discusses the Passive Component Inspection Activities for providing periodic visual examinations to identify and find any significant aging effects. However, this program is not listed in Table 3.2.3-4 of the LRA as an applicable AMP for stainless steel piping exposed to a wetted gas environment. Resolve this discrepancy.

RESPONSE TO RAI 3.3-HPCI-3:

Section C.1.2.6.2 of the LRA notes that a temperature threshold of 140 °F was assumed for SCC of stainless steels. Only those stainless steel components that contain humid or wet gases under normal conditions, and are subject to normal operating temperatures in excess of 140 °F, were determined to require inspection in accordance with the PCIA. Stainless steel components subject to temperatures less than the 140 °F limitation are less susceptible to corrosion processes, and therefore, are managed by a one-time inspection accomplished in accordance with the GSCI.

Additionally, commodity sections in Appendix C.2 of the Plant Hatch LRA present all of the AMPs applicable to the specific commodity under consideration. Note that <u>all</u> of the AMPs presented in each Appendix C.2 section do not necessarily apply to <u>all</u> of the components included within the commodity. The Plant Hatch LRA Section 3 tables provide this component-specific information.

RAI 3.3-HPCI-4:

Based on Table 3.2.3-4 of the LRA, carbon steel pump casing exposed to a demineralized water environment is a non-class 1 commodity discussed further in Section C.2.2.2.1 of the LRA. This section discusses the Galvanic Susceptibility Inspections for providing appropriate examinations of carbon steel to stainless steel dissimilar metal welds to identify potential loss of material due to galvanic corrosion. However, this program is not listed in Table 3.2.3-4 of the LRA as an applicable AMP for carbon steel pump casing exposed to a demineralized water environment. Resolve this discrepancy.

RESPONSE TO RAI 3.3-HPCI-4:

There are no dissimilar metal welds between the HPCI pump casings and connected piping components. Thus, corrosion due to a galvanic couple is not possible, and the galvanic susceptibility inspection does not apply to these casings.

Section C.2.2.2.1 of the Plant Hatch LRA presents all of the aging management programs applicable to that commodity. Note that <u>all</u> of the AMPs presented in each Appendix C.2 section do not necessarily apply to <u>all</u> of the components included within the commodity. The Plant Hatch LRA Section 3 tables provide this component-specific information.

RAI 3.3-HPCI-5:

Based on Table 3.2.3-4 of the LRA, stainless steel restricting orifice exposed to a demineralized water environment is a non-class 1 component discussed further in Section C.2.2.2.2 of the LRA. This section discusses loss of material and cracking due to thermal fatigue as applicable aging effects. However, cracking due to thermal fatigue is not listed in Table 3.2.3-4 of the LRA as an applicable aging effect for this component. Resolve this discrepancy.

RESPONSE TO RAI 3.3-HPCI-5:

To facilitate the NRC review of the cracking aging mechanisms discussed in the various Appendix C commodity groups, a matrix was provided to the NRC on June 20, 2000. This matrix provides a concise way for the NRC to determine which cracking mechanisms are considered applicable when examining the six column tables.

Although LRA Table 3.2.3-4 inadvertently omitted thermal fatigue as an aging effect requiring management applicable to the restricting orifice under consideration, the June 20, 2000 matrix provided to the NRC staff does identify thermal fatigue as applicable for components within commodity group C.2.2.2.2. Although piping is realistically the bounding component type for fatigue failures, the TLAA for non-Class 1 piping components is valid for all component types, including valves and restricting orifices.

RAI 3.3-HPCI-6:

Based on Table 3.2.3-4 of the LRA, stainless steel restricting orifice exposed to a wetted gas environment is a non-class 1 component discussed further in Section C.2.2.9.2 of the LRA. This section discusses the Passive Component Inspection Activities as an applicable AMP for this component. However, the Passive Component Inspection Activities is not listed in Table 3.2.3-4 as an applicable AMP for this component. Resolve this discrepancy.

RESPONSE TO RAI 3.3-HPCI-6:

See the response to RAI 3.3-HPCI-3.

RAI 3.3-HPCI-7:

Based on Table 3.2.3-4 of the LRA, the carbon steel turbine exposed to a wetted gas environment is a non-class 1 component discussed further in Section C.2.2.9.1. This commodity group includes the HPCI turbine pressure boundary components. The staff requests the applicant to identify the component(s) in the listing of "turbine" in Table 3.2.3-4.

RESPONSE TO RAI 3.3-HPCI-7:

A turbine is an active component. However, SNC has evaluated the pressure boundary function of the HPCI turbine. This resulted in the turbine upper and lower half casings being subject to an AMR.

RAI 3.3-HPCI-8:

Based on Table 3.2.3-4 of the LRA, the carbon steel valve bodies exposed to demineralized water is a non-class 1 component discussed further in Section C.2.2.2.1 of the LRA. This section discusses the Treated Water Systems Piping Inspections as an applicable AMP for this commodity group. However, this inspection AMP is not listed in Table 3.2.3-4 as an applicable AMP for this component. Resolve this discrepancy.

RESPONSE TO RAI 3.3-HPCI-8:

For carbon steel valve bodies exposed to demineralized water in LRA Table 3.2.3-4, the TWSPI was inadvertently omitted from this table.

RAI 3.3-HPCI-9:

Based on Table 3.2.3-4 of the LRA, the carbon steel and stainless steel valve bodies exposed to a wetted gas environment are non-class 1 components discussed further in Section C.2.2.9.1 and Section C.2.2.9.2 of the LRA. These sections discuss Passive Component Inspection Activities as an applicable AMP for these components. However, these activities are not listed in Table 3.2.3-4 an as applicable AMP for these components. Resolve this discrepancy.

RESPONSE TO RAI 3.3-HPCI-9:

See the responses to RAIs 3.3-HPCI-3 and 3.4-4.

Carbon steel valve bodies exposed to wetted gas in Table 3.2.3-4 of the Plant Hatch LRA should include the PCIA as part of appropriate aging management. The PCIA notation was inadvertently omitted from this line item in Table 3.2.3-4.

RAI 3.3-HR-1:

Based on Table 3.2.3-8 of the LRA, stainless steel valve bodies exposed to a wetted gas environment are non-class 1 components discussed further in Section C.2.2.9.2 of the LRA. This section discusses the Passive Component Inspection Activities as an applicable AMP for this component. However, the Passive Component Inspection Activities is not listed in Table 3.2.3-8 as an applicable AMP for this component. Resolve this discrepancy.

RESPONSE TO RAI 3.3-HR-1:

See the response to RAI 3.3-HPCI-3. Based on the normal operating temperature of the valve bodies (< 140 °F), the PCIA is not applicable. SNC will manage the aging in these valves through the GSCI.

RAI 3.3-P&I-1:

Based on Table 3.2.3-7 of the LRA, carbon steel piping exposed to torus water is a non-class 1 component discussed further in Section C.2.2.3.1 of the LRA. This section discusses the Protective Coatings Program as an applicable AMP for these components. However, this program is not listed in Table 3.2.3-7 as an applicable AMP for this component. Resolve this discrepancy.

RESPONSE TO RAI 3.3-P&I-1:

As indicated in the electronic communication to NRC on April 19, 2000, the protective coatings program is an applicable AMP for non-Class 1 carbon steel piping exposed to torus water.

RAI 3.3-P&I-2:

Based on Table 3.2.3-7 of the LRA, stainless steel thermowell exposed to an inside environment is a non-class 1 component discussed further in Section C.2.2.9.2 of the LRA. This section discusses the Passive Component Inspection Activities as an applicable AMP for this component. However, the Passive Component Inspection Activities is not listed in Table 3.2.3-7 as an applicable AMP for this component. The staff requests the applicant to clarify this discrepancy.

RESPONSE TO RAI 3.3-P&I-2:

LRA Table 3.2.3-7 lists the aging management programs relied on by the components supporting T48 intended function. Section C.2.2.9.2 describes AMPs relied on to manage aging effects for the various components within a humid or wetted environment, including the containment purge and inerting system. The cracking aging effect that is shown in Table 3.2.3-7 for the thermowell is cracking due to thermal fatigue. Cracking due to thermal fatigue is managed by design through a TLAA (see LRA Section 4.2).

See the response to RAI 3.3-HPCI-3. The thermowell listed in Table 3.2.3-7 is located in an environment that normally operates at a temperature less than 140 °F.

RAI 3.3-RCIC-1:

Based on Table 3.2.3-5 of the LRA, stainless steel piping exposed to a wetted gas environment is a non-class 1 component discussed further in Section C.2.2.9.2 of the

LRA. This section discusses the Passive Component Inspection Activities as an applicable AMP for this component. However, these activities are not listed in Table 3.2.3-5 as an applicable AMP for this component. Resolve this discrepancy.

RESPONSE TO RAI 3.3-RCIC-1:

See the response to RAI 3.3-HPCI-3.

RAI 3.3-RCIC-2:

Based on Table 3.2.3-5 of the LRA, carbon steel pump casing exposed to a demineralized water environment is a non-class 1 component discussed further in Section C.2.2.2.1 of the LRA. This section discusses Galvanic Susceptibility Inspections as an applicable AMP for this component. However, this inspection is not listed in Table 3.2.3-5 of the LRA as an applicable AMP for this component. Resolve this discrepancy.

RESPONSE TO RAI 3.3-RCIC-2:

There are no dissimilar metal welds between the RCIC pump casings and connected piping components. Thus, corrosion due to a galvanic coupling is not possible and the galvanic susceptibility inspection does not apply to these casings.

Additionally, as noted in the response to RAI 3.3-HPCI-3, commodity sections in Appendix C.2 of the Plant Hatch LRA present all of the AMPs applicable to the specific commodity under consideration. Note that all of the AMPs presented in each Appendix C.2 section do not necessarily apply to all of the components included within the commodity. The Plant Hatch LRA Section 3 tables provide this component-specific information.

RAI 3.3-RCIC-3:

Based on Table 3.2.3-5 of the LRA, stainless steel restricting orifice exposed to a demineralized water environment is a non-class 1 component discussed further in Section C.2.2.2.2 of the LRA. This section discusses loss of material and cracking due to thermal fatigue as applicable aging effects. However, cracking due to thermal fatigue is not listed in Table 3.2.3-5 of the LRA as an applicable aging effect for this component. Resolve this discrepancy.

RESPONSE TO RAI 3.3-RCIC-3:

See the response to 3.3-HPCI-5.

RAI 3.3-RCIC-4:

Based on Table 3.2.3-5 of the LRA, stainless steel restricting orifice exposed to a wetted gas environment is a non-class 1 component discussed further in Section C.2.2.9.2 of the LRA. This section discusses the Passive Component Inspection Activities as an applicable AMP for this component. However, the Passive Component Inspection Activities is not listed in Table 3.2.3-5 as an applicable AMP for this component. Resolve this discrepancy.

RESPONSE TO RAI 3.3-RCIC-4:

See the response to RAI 3.3-HPCI-3.

RAI 3.3-RCIC-5:

Based on Table 3.2.3-5 of the LRA, carbon steel steam trap exposed to reactor water is a non-class 1 commodity discussed further in Section C.2.2.1.1 of the LRA. This section describes the Galvanic Susceptibility Inspections as an applicable AMP for this component. However, this program is not listed in Table 3.2.3-5 of the LRA as an applicable AMP for this component. Resolve this discrepancy.

RESPONSE TO RAI 3.3-RCIC-5:

See the response to RAI 3.3-HPCI-4.

There are no dissimilar metal welds between the steam trap under consideration and connected piping components. Thus, corrosion due to a galvanic couple is not possible and the galvanic susceptibility inspection does not apply to this steam trap.

RAI 3.3-RCIC-6:

Based on Table 3.2.3-5 of the LRA, carbon steel thermowell exposed to demineralized water is a non-class 1 commodity discussed further in Section C.2.2.2.1 of the LRA. This section describes the Galvanic Susceptibility Inspections as an applicable AMP for this component. However, this program is not listed in Table 3.2.3-5 of the LRA as an applicable AMP for this component. Resolve this discrepancy.

RESPONSE TO RAI 3.3-RCIC-6:

See the response to RAI 3.3-HPCI-4.

There are no dissimilar metal welds between the thermowell under consideration and connected piping components in a demineralized water environment. Thus, corrosion due to a galvanic couple is not possible and the galvanic susceptibility inspection does not apply to this thermowell.

RAI 3.3-RCIC-7:

Based on Table 3.2.3-5 of the LRA, stainless steel valve bodies exposed to a demineralized water environment is a non-class 1 component discussed further in Section C.2.2.2.2 of the LRA. This section discusses loss of material and cracking due to thermal fatigue as applicable aging effects. However, cracking due to thermal fatigue is not listed in Table 3.2.3-5 of the LRA as an applicable aging effect for this component. Resolve this discrepancy.

RESPONSE TO RAI 3.3-RCIC-7:

See the response to RAI 3.3-HPCI-5.

Although LRA Table 3.2.3-5 inadvertently omitted thermal fatigue as an aging effect requiring management applicable to the stainless steel valve bodies under consideration, the June 20, 2000 matrix provided to the NRC staff does identify thermal fatigue as applicable for components within commodity group C.2.2.2.2.

RAI 3.3-SGTS-1:

Based on Table 3.2.3-6 of the LRA, stainless steel piping exposed to air is a non-class 1 component discussed further in Section C.2.2.9.2 of the LRA. This section discusses the Passive Component Inspection Activities as an applicable AMP for this component. However, the Passive Component Inspection Activities is not listed in Table 3.2.3-6 as an applicable AMP for this component. Resolve this discrepancy.

RESPONSE TO RAI 3.3-SGTS-1:

See the response to RAI 3.3-HPCI-3. Based on the normal operating temperature of the stainless steel piping (< 140 °F), SNC will manage the aging in these valves through the GSCI.

RAI 3.3-SGTS-2:

Based on Table 3.2.3-6 of the LRA, stainless steel thermowell and valve bodies exposed to air are non-class 1 components discussed further in Section C.2.2.9.2 of the LRA. This section discusses the Passive Component Inspection Activities as an applicable AMP for these components. However, the Passive Component Inspection Activities is not listed in Table 3.2.3-6 as an applicable AMP for these components. Resolve this discrepancy.

RESPONSE TO RAI 3.3-SGTS-2:

See the response to RAIs 3.3-HPCI-3 and 3.3-SGTS-1. Based on the normal operating temperature of the thermowells and valve bodies (< 140 °F), SNC will manage the aging in these valves through the GSCI.

AUXILIARY SYSTEMS

RAI 3.4-1:

The control rod drive, plant service water, reactor building closed cooling water, instrument air, primary containment chilled water, and drywell pneumatics systems each contain carbon and low alloy carbon steel bolts fabricated to the requirements of ASTM A-307 (grade B), ASME SA 194 (grade 2H), and ASME SA 193 (grade B7) and exposed to inside and/or outside environments. The applicant evaluated the aging effects for these materials and environments in Sections C.1.2.7, C.1.2.8 and C.1.2.9 of the application and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, pitting, crevice corrosion). The applicant also identified loss of preload as an applicable aging effect for bolting due to various mechanisms (e.g., embedment, gasket creep, thermal effects, self-loosening). The staff considers the high strength bolting materials, fabricated to ASME SA 193, grade B7 to be potentially susceptible to stress corrosion cracking (SCC). Discuss why SCC is not considered an applicable aging effect for this particular group of bolting materials.

RESPONSE TO RAI 3.4-1:

A report was completed by EPRI (EPRI NP-5769, Volume 1, April 1988, "Degradation and Failure of Bolting in Nuclear Power Plants") that states the results of evaluations of bolting failures in the nuclear power industry. Concerning SCC in bolts, the report states in part:

> "The stress corrosion cracking field experience involving these bolting materials [*which include the low alloy carbon steel bolts in question*] can be categorized in two groups:
>
> "Group I – Materials specified as ultra-high strength with specified minimum yield strengths greater than 150 ksi that failed due to the combination of stress and environmental factors. Failures that have occurred involve materials with intentionally high strength requirements, and the integrity of these materials is directly questioned by the field experience. Failure events occurred both during service and construction, and multiple fastener failures have been observed.
>
> "Group II – High strength materials with specified minimum yield strengths equal to or less than 150 ksi that failed because of poor heat treatment and material variability. In contrast to Group I, the failure events associate with the Group II category involve materials that are unintentionally high strength. These failure events are related to poor quality control, and all bolt failures occurred and were detected during plant construction."

Based on this information, bolting materials with a minimum yield strength of less than 150 ksi have generally not been considered a candidate for SCC.

An evaluation of this information is contained in NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants." This evaluation advises that bolting with a stated minimum yield strength of $\leq$ 150 ksi may have a much higher actual yield strength. Therefore, it is recommended that actual yield strength be used in determining whether or not bolting materials are susceptible to SCC based on the 150 ksi criterion.

The specific bolting material in question has a minimum yield strength of 105 ksi. Because plant procedures require torque values significantly lower than the minimum yield strength, the occurrence of localized stress in excess of 150 ksi is considered to be unlikely.

Other mitigating factors to be considered are:

1. All of the bolts in question are in environments of less than 140°F.
2. All of the bolts in question are in relatively benign chemical environments.
3. For normally dry, properly torqued bolting material, SCC is not expected without an additional contributing event such as leakage. This contributing event may provide an indicator of possible SCC before loss of component function.
4. Industry operating experience reveals SCC in low alloy bolting has generally been associated with high temperatures (e.g., reactor coolant system, HPCI steam side); aggressive chemical environment (e.g., borated systems); or additional contributing factors (e.g., joint leakage).

Based on this information, SCC is not considered an aging mechanism requiring evaluation in an AMR for the specific bolting material applications in question.

RAI 3.4-2:

The applicant relies on one-time inspection, the treated water systems piping inspections, to manage loss of material due to erosion corrosion for carbon steel components in the control rod drive system and the emergency diesel generator system. The applicant provided a discussion of operating experience that included past failures in these systems due to erosion corrosion. The staff does not consider a one-time inspection program adequate to manage an ongoing problem with erosion corrosion. Provide additional information that justifies your use of a one-time inspection program to manage erosion corrosion for these systems. Also, clarify Table C.2.2.2-2 of the application, specifically attribute number 4, in which you state that the program provides for "periodic inspections." This attribute is not consistent with the program description in other portions of this commodity group discussion nor is it consistent with the program description in appendix A.3.3.

RESPONSE TO RAI 3.4-2:

This response clarifies the aging mechanism, erosion-corrosion, in order to differentiate it from FAC, the aging mechanism that receives surveillance. It appears that the term erosion-corrosion may have been interpreted as the aging mechanism SNC terms FAC.

Erosion-corrosion referred to in Section C.2.2.2.1 of the LRA is an aging mechanism that results in loss of metal through the repetition of a process that leads to thinning of the metal. Erosion-corrosion is the loss of material caused by the combined actions of erosion by a flowing fluid, and corrosion of newly exposed base material by the environment. Protective oxide films that develop on metal surfaces are mechanically removed by the flowing fluid, exposing bare metal surface to further film production. The repetition of this process leads to thinning of the metal.

The FAC aging mechanism is similar, but occurs under different internal fluid conditions. The rate of material loss due to FAC depends on a complex interplay of many parameters, including flow, water chemistry, temperature, service hours, and material composition. The FAC program evaluated the components for FAC in accordance with industry guidance, and SNC determined that the fluid conditions did not warrant traditional FAC surveillance. However, because the less aggressive erosion-corrosion mechanism can not be ruled out for the subject components, a one-time, confirmatory inspection of the components is appropriate.

The TWSPI AMP is credited for inspection of locations that have the potential for loss of material due to erosion-corrosion, as described above. For the cited systems and environments, including the CRD and EDG systems, the actual mechanism of loss of material does not follow the traditional mechanism of FAC. Rather, the material is lost through a cycle of erosion of the metal, formation of a corrosion product oxide layer, and then re-erosion of that layer.

The discussion of operating experience in LRA Section C.2.2.2.1 that included past failures due to erosion-corrosion are FAC-related, and apply to systems such as HPCI and RCIC steam supply drain lines. No failures in the components covered by Section C.2.2.2.1 have occurred due to loss of material from erosion-corrosion.

Attribute 4 of LRA Table C.2.2.2-2 incorrectly states the TWSPI will provide for periodic inspections. The attribute should read as follows: "The TWSPI provide a one-time inspection of components susceptible to erosion-corrosion and similar mechanisms".

RAI 3.4-3:

LRA Tables 3.2.4-1, 3.2.4-12, 3.2.4-15, 3.2.4-17, 3.2.4-18, 3.2.4-19, and 3.2.4-20 identify air and carbon dioxide as environments. However, there is no specific commodity group discussion of either air or carbon dioxide in the application. Clarify the environment to which "air" and "carbon dioxide" belong.

RESPONSE TO RAI 3.4-3:

For the purposes of evaluating in-scope components for aging effects, SNC considers "carbon dioxide" to be a dry gas. In the LRA, carbon dioxide is a dry gas in the C.2.2.8 sections, as well as the fire protection section, C.2.3.

SNC has conservatively assumed "air" to be a moist gas internal environment. Appendix C.2.2.9 sections address the AMR for components with an internal air environment.

RAI 3.4-4:

Commodity group C.2.2.9 describes the AMR for a wetted gas environment. This commodity group has four subsections to address four material types: carbon steel/cast iron, stainless steel, copper/copper alloys, and galvanized steel/aluminum.

a. In the stainless steel and copper alloy subsections, C.2.2.9.2 and C.2.2.9.3, respectively, loss of material and cracking are discussed as aging effects. However, Tables 3.2.4-1, 3.2.4-15 and 3.2.4-20 of the LRA have several stainless steel, galvanized steel, copper alloy and aluminum components that do not reflect this determination. Clarify these discrepancies.

b. In subsections C.2.2.9.1, C.2.2.9.2 and C.2.2.9.4 of the LRA, the applicant relies on the gas systems component inspections and the passive component inspection activities. Discuss why C.2.2.9.3 does not similarly refer to the passive component inspection activities to manage aging. The aging effects for this subgroup are identical to the other three subgroups.

c. The referenced AMPs in Tables 3.2.4-1, 3.2.4-6, 3.2.4-12, 3.2.4-15, 3.2.4-17, 3.2.4-19, and 3.2.4-20 of the LRA do not match the commodity group discussion for various copper alloy, stainless steel, galvanized steel, and aluminum components in Section C.2.2.9 of the LRA. Clarify these discrepancies.

RESPONSE TO RAI 3.4-4:

In understanding the use of the GSCI and the PCIA to manage the effects of aging in gas systems that can contain moisture, it is necessary to understand SNC's philosophy with respect to the PCIA. The PCIA provides an on-going, early detection mechanism for components in which aging effects are more likely to occur. The GSCI will be used to assure that a sufficient sample of components is inspected on a one-time basis to provide a strong assurance that aging effects are not occurring in the components. Stainless steel is a hardy material, and not prone to aging effects in the gas environments evaluated in Section C.2.2.9.2. So, also, is copper. For this reason, the PCIA will not be applied to most of those components.

a. Cracking for stainless steel occurs through the mechanisms of thermal fatigue and SCC for the components evaluated in section C.2.2.9.2 of the LRA. Thermal fatigue of stainless steel components evaluated in section C.2.2.9.2 was addressed in the initial design, and is managed through TLAAs. SCC can occur in stainless steel piping, but is unlikely to occur in systems that normally operate under 140 °F, as is the case with most of the components evaluated in Section C.2.2.9.2. SCC is managed for the components in this section through the GSCI. In this section, those few components that normally operate above 140 °F also fall in the scope of the PCIA. If the only mechanism for cracking is thermal fatigue then no program will appear in Tables 3.2.4-1, 3.2.4-15, and 3.2.4-20 for that aging effect. If SCC is an aging effect requiring management, then the GSCI will appear, and the PCIA may also appear if the normal operating conditions of the component indicate the additional management provided by the PCIA, as noted above.

An example of the implementation of this discussion appears in LRA Table 3.2.4-20, where the stainless steel thermowell has no aging management program. The thermowell is only susceptible to thermal fatigue, as the configuration of the thermowell will not allow pooling of water to enable SCC. Thermal fatigue is managed through a TLAA, and the table, therefore, indicates "None Required" in the Aging Management Program/Activity column.

For the components evaluated in LRA Section C.2.2.9.2, loss of material occurs through several aging mechanisms. SNC will use the GSCI to manage loss of material for the components evaluated in Section C.2.2.9.2.

For Section C.2.2.9.3, the aging mechanism for cracking in these copper alloy components is thermal fatigue. As with the stainless steel components in Section C.2.2.9.2, thermal fatigue was included in the original design, and the aging effect is managed through TLAA.

Loss of material is an aging effect that requires an AMR for copper components evaluated in Section C.2.2.9.3. Loss of material in moist air is not a particularly likely or aggressive effect. To assure that the aging effect is not causing a loss of component function, SNC will use the GSCI for the copper components.

b. For Section C.2.2.9.3, the aging mechanism that causes cracking is thermal fatigue – not SCC. Thermal fatigue of copper components has been addressed in the original design, and is managed through a TLAA. SNC, therefore, does not rely on the PCIA to manage cracking of copper components. Loss of material is an aging effect that requires an AMR for copper components evaluated in Section C.2.2.9.3. Loss of material in moist air is not a likely or aggressive effect. To assure that the aging effect is not causing a loss of component function, SNC will use the GSCI for the copper components.

c. Insufficient information is supplied in this portion of the RAI to determine if discrepancies actually exist in the tables. After reviewing the tables, SNC found its approach to implementing the PCIA and GSCI is consistent, and is reflected in the Section 3.2.4 tables consistently.

RAI 3.4-5:

Table 3.2.4-19 of the LRA references commodity group C.2.2.9 for the stainless steel thermowell exposed to an inside environment. This commodity group does not discuss an inside environment, and the aging effects discussed in this commodity group do not match the aging effects or AMPs discussed in the table. Clarify these discrepancies. Similarly, Table 3.2.4-20 of the LRA references C.2.2.9.4 for galvanized steel and carbon steel exposed to an inside environment. This commodity group does not discuss an inside environment, although in this case the aging effects and AMPs match those referenced in the table. There are several places in the auxiliary system discussions in Section 3.2.4 in which galvanized steel exposed to an inside or outside environment is said to suffer loss of material or cracking (e.g., Table 3.2.4-3 - insulation bolting, Table 3.2.4-18, kaowool hold down straps). However, there is no discussion of such aging effects in the application. Clarify the aging effects for galvanized steel exposed to an inside or outside environment.

RESPONSE TO RAI 3.4-5:

The RAI apparently is referring to LRA Table 3.2.4-20, since no stainless steel thermowells appear on Table 3.2.4-19. LRA Table 3.2.4-20 links to Section C.2.2.9 for the AMR for the surface of the thermowell that is exposed to a wetted gas environment (in this case, potentially moist air). SNC determined that only cracking due to thermal fatigue is an aging effect requiring further evaluation in an AMR for this component. This aging effect is managed by a TLAA. The TLAA associated with thermal fatigue in the piping bounds thermal fatigue in the thermowell.

LRA Section C.2.4.1 provides the AMR for the exterior surfaces of the components exposed to an inside environment. This section includes carbon steel, stainless steel, and galvanized steel. Similarly, Section C.2.4.2 provides the AMR for the exterior surfaces of the components exposed to an outside environment. Galvanized steel components that support Z41 intended functions are included in the scope of the PCIA. That is why the table refers to Section C.2.2.9. Galvanized kaowool hold down straps in LRA Table 3.2.4-18 may exhibit cracking and a change in material properties in an inside environment. Aging effects for these, and other components located in an inside environment, are described in LRA Section C.1.2.8. The galvanized steel bolting in LRA Table 3.2.4-3 may exhibit loss of material and cracking in an outside environment. Aging effects for these, and other galvanized steel components located in an outside environment, are described in LRA Section C.1.2.9, and evaluated in Sections C.2.2.9.4, C.2.4.1, C.2.4.2, and C.2.4.4.2.

RAI 3.4-6:

Discuss why fouling is not considered an applicable aging effect for certain components exposed to fuel oil. Section C.1.2.5.3 states that fouling is applicable to copper tubing supply lines for the fire protection pump diesel engine but this is not in 3.2.4-18 nor is it in the commodity group discussion. Also, Information Notice 91-46, "Degradation of Emergency Diesel Generator Fuel Oil Delivery Systems," indicates that several plants have experienced clogging of strainers with sediment and degraded fuel oil. Also, discuss why selective leaching is not considered to be an applicable aging effect for the cast iron and copper alloy components exposed to fuel oil, given the potential exposure to water.

RESPONSE TO RAI 3.4-6:

LRA Section C.1.2.5.3 incorrectly stated that flow blockage is an applicable aging effect for copper tubing exposed to fuel oil.

Section C.1.2.4.1 evaluates loss of material that could lead to fouling. The results are given in Table 3.2.4-18. The periodic removal of water from the tanks minimizes the potential for corrosion product buildup in the fuel oil system. Loss of material resulting from selective leaching is evaluated in Section C.1.2.4 with the results shown in Table 3.2.4-18.

Operating experience indicates no age-related failure of the fuel oil components. Therefore, managing fuel oil quality sufficiently manages the effects of aging for fuel oil components.

RAI 3.4-7:

Previous license renewal applications provided one-time inspections to verify the effectiveness of their diesel fuel oil testing programs. Discuss why such a confirmatory program is not needed at Hatch.

RESPONSE TO RAI 3.4-7:

See Appendix B, Section 1.3 for a discussion of the diesel fuel oil testing activities credited for license renewal. The diesel fuel oil testing program provides limits for impurities in the fuel oil, including water and particulates, thus limiting the likelihood of aging effects being present in the tanks. Based on the information presented in LRA Section C.2.2.7, the activities described in Appendix A.1.3 are adequate to manage aging in the renewal term.

RAI 3.4-8:

Many commodity groups discuss several AMPs, but not all of these AMPs are applied similarly across the various systems that reference the commodity group. For example, in commodity group C.2.4.1 of the license renewal application, the applicant cited both the protective coatings program and fire protection activities to manage aging effects (e.g., loss of material) due to exposure of various materials to an inside environment. However, it is apparent from the system descriptions in section 3.2.4 of the license renewal application that not all systems benefit from the fire protection activities program. To aid in its review, the staff requests the applicant clarify, for commodity groups that reference more than one AMP, the differences in the application of the AMPs to the various systems referenced in the commodity group.

RESPONSE TO RAI 3.4-8:

The RAI is apparently referring to Section 2.4 of the LRA for the system descriptions, rather than Section 3.2.4. Sections 2.3 through 2.5 of the LRA present the scoping and screening results. Thus, structures and components subject to aging management review are identified in the Section 2.3 through 2.5 tables. Section 3 provides a corresponding table for each Section 2.3 through 2.5 table that summarizes the results of the AMRs for each component group identified. In the Section 3 tables, reference is made to specific Appendix C sections for a discussion of the aging management of each component group. The Appendix C sections, such as Appendix C.2.4.1 mentioned in the RAI, consolidate the aging management discussion for all structures or components that are constructed of similar materials and are exposed to similar environments. All aging management activities that are credited for any subset of the components characterized by a commodity group such as is described in Appendix C.2.4.1 are identified in the commodity group discussion. However, for any specific structure or component, the review can clearly identify the set of aging management activities by examining the line item entry for that structure or component in the appropriate Section 3 table.

One aspect of LRA Section C.2.4 that should be reiterated is that this section contains the AMR results for all mechanical component external surfaces, including fire protection components. AMR results for fire protection components exposed to all other environments are presented in Section C.2.3. Obviously, the only components for which fire protection activities are credited are those associated with the various fire protection systems. Also, see Appendix B, Section 2.1

RAI 3.4-9

The applicant stated that selective leaching is an applicable aging effect for certain types of materials in certain environments. The applicant has not provided a specific AMP for this mechanism. Given that selective leaching may not be detectable through standard visual inspections, discuss how your various inspection programs are adequate to manage this particular aging mechanism.

RESPONSE TO RAI 3.4-9:

Brass and gray cast iron components perform passive functions in the service water and fire protection systems. The fire protection components' functionality is closely linked to performance and condition characteristics that are currently monitored through fire protection activities. Furthermore, no age-related failures were identified for these components in the Plant Hatch operating history. However, SNC has conservatively committed to destructively examine one 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 to June 13, 2018 for Unit 2.

RAI 3.4-10:

Based on the staff's experience, degradation of piping systems (e.g., loss of integrity of bolted closures, cracking of welds and loosening of bolts) may potentially be caused by vibration (mechanical or hydrodynamic) loading. The vibration related aging effects as identified in Table 3.2.4 of the license renewal application appear to be incomplete. Respond to the following staff concerns below:

a. In Table 3.2.4, the applicant often referred to "cracking" as an aging effect. Because cracking can be caused by different mechanisms (e.g., thermal fatigue, vibration fatigue, or stress corrosion), the aging management program attributes may differ significantly. Specify the mechanism causing the cracking referenced in the table.

b. In Table 3.2.4, the applicant identified loss of preload as an aging effect for bolting in many of the auxiliary systems, including HVAC systems. In Section

C.1 of the application, the applicant indicated that loss of preload included self-loosening of boltings that may be caused by vibration. However, it is not clear whether the applicant has considered cracking of piping welds and of HVAC ducting which may potentially be subjected to a high vibration environment. Clarify whether these vibration-related aging effects have been considered in the aging review for the auxiliary systems discussed in Section 3.2.4 of the license renewal application. In addition, specifically discuss why the aging effect of self-loosening of bolted connections due to vibration is not considered for the cranes, hoists and elevators system as well as other auxiliary systems.

c. In Table 3.2.4-12, the applicant did not identify loss of preload as an aging effect for bolting in the EDG system. Since the EDG system may potentially be subjected to a high vibration environment, provide the basis for excluding loss of preload as an aging effect for bolting in that piping system. Also, clarify whether cracking of piping welds due to vibration was considered in the aging review for the EDG system, and if they were excluded, provide the basis.

RESPONSE TO RAI 3.4-10:

a. By electronic communication on June 20, 2000, SNC provided NRC with an application guide to assist in determining the mechanism for cracking cited in the tables in LRA Section 3.2.4.

b. Vibration induced cracking of pipe welds and HVAC ducting is indicative of an insufficient design or bolting practice following maintenance. Such cracking would manifest itself quickly during plant operation. Thus, vibration induced fatigue is not an aging effect requiring management for Plant Hatch. With regard to structural bolting, see the response to RAI 3.6-50.

c. Bolting is not a separate mechanical component/commodity requiring aging management for the EDG system. Therefore, bolting is not included in Table 3.2.4-12.

RAI 3.4-11:

The scoping requirements of 10 CFR 54.4(a)(2) includes all non safety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs 10 CFR 54.4(a)(1)(i), (ii), or (iii). In Section 2.1.2.5 of the license renewal application, the applicant stated that the few cases where non safety-related components could impact safety-related functions were included in the scope of license renewal in accordance with the criteria of 10CFR54.4(a)(2). Please clarify whether the scope of the auxiliary systems discussed in Section 3.2.4 of the license renewal application 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. In addition, clarify how the AMPs for the non safety-related systems and components have been addressed. Specifically, state whether the same AMPs discussed in Table 3.2.4 of the application also apply to those "Seismic II over I" piping components.

RESPONSE TO RAI 3.4-11:

Intended function L35-01 captures all safety related and nonsafety-related supports for components in configurations that could potentially result in loss of function for Seismic Category I components based on spatial relationships. The key element in managing both Seismic Category I systems, and non-Category I systems so that no impact on safety related functions occur, is to assure that aging effects for the supports encompassed by the L35-01 function are appropriately managed. Based on the body of empirical evidence related to piping and piping supports under seismic loadings, managing aging effects associated with the piping supports for systems otherwise not-in-scope is adequate to assure no loss of function for safety related functions. Thus, no AMPs are applied to the not-in-scope piping segments supported by Seismic II over I piping supports.

RAI 3.4-12:

This question applies to the reactor building HVAC system and the control building HVAC system. Ductwork generally includes isolators (such as flexible collars between ducts and fans, seals in dampers and doors, etc) made of elastomers, which will degrade because of relative motion between vibrating equipment, exposure to warm moist air, temperature changes, oxygen, and/or radiation. This environment may cause degradation of elastomers resulting in hardening and loss of strength. Because of the degradation of isolators, vibration and subsequent dynamic loads applied to the ductwork and fasteners cannot be eliminated. Provide the technical justification for not considering degradation of the isolators as an applicable aging effect.

RESPONSE TO RAI 3.4-12:

The degradation of isolators made of elastomers, including gaskets and flexible connectors in HVAC duct systems, has been considered. The principal degradation was determined to be cracking due to thermal exposure. The isolators are shown on LRA Table 3.2.4-20 as "ductwork flex connectors," and the AMR is presented in Section C.2.6.7. SNC concluded that GSCI and PCIA would be used to manage this aging effect. See Appendix B, Sections 3.3 and 3.5.

RAI 3.4-CBHVAC-1:

The CBHVAC system contains various components fabricated from carbon steel, fibers, nonasbestos synthetic, elastomers, aluminum, galvanized, stainless steel, and copper alloy exposed to an air environment. The applicant evaluated the aging effects for these materials and environment in sections C.2.2.9.1, C.2.2.9.2, C.2.2.9.3, C.2.2.9.4, and C.2.6.7 of the application, and identified cracking and loss of material for carbon steel, stainless steel, and galvanized steel, and material property changes for fibers, nonasbestos synthetics, and elastomers as the aging effects. The staff is not aware of any mechanism for loss of material for stainless steel in an air environment. Please discuss the identification of this aging effect.

RESPONSE TO RAI 3.4-CBHVAC-1:

SNC determined for the stainless steel components of the MCRECS identified above, that the aging effect of loss of material due to the aging mechanisms of crevice, pitting, and microorganism-induced corrosion in a humid air environment required further evaluation. Evaluation results indicated that these aging effects, if present, were not likely to be aggressive in nature. Therefore, SNC has conservatively chosen to include these components in the scope of the GSCI.

RAI 3.4-CHE-1:

Expansion and undercut anchors in concrete may become loose due to local degradation of the surrounding concrete as a result of vibratory loads. Provide the technical justification for not identifying loss of preload due to the effects of vibration on concrete surrounding expansion and undercut anchors.

RESPONSE TO RAI 3.4-CHE-1:

Loosening of expansion and undercut type concrete anchors may occur when the concrete is of poor quality, when the anchors are subjected to large magnitude cyclical loads, or when the anchors are subjected to shear and/or tension forces near the bolt allowables. Expansion and undercut anchors are not used in applications where the anchors experience significant vibration. The concrete used at Plant Hatch is of excellent quality in accordance with the requirements of ACI 318-63.

RAI 3.4-COND-1:

The applicant discussed the aging effects associated with various materials exposed to a demineralized water environment in section C.1.2.2 of the application. The applicant identified cracking due to thermal fatigue as an aging effect. However, the applicant did not include cracking due to thermal fatigue as an aging effect for the condensate transfer and storage tanks. Neither Table 3.2.4-5 nor commodity group C.2.2.2.3 includes cracking due to thermal fatigue as an aging effect. Clarify this discrepancy.

RESPONSE TO RAI 3.4-COND-1:

Thermal fatigue occurs when a component that is restrained undergoes rapid thermal cycling. The CSTs contain very large masses of water, so any temperature change is extremely slow. The tanks are also free to expand. Therefore, SNC concluded that thermal fatigue is not an aging effect requiring management for the CSTs, and LRA Table 3.2.4-5 and Section C2.2.2.3 do not include thermal fatigue as an aging effect requiring management for the CSTs.

RAI 3.4-CRD-1:

The control rod drive system contains valve bodies fabricated from copper alloys and exposed to an air environment. The applicant assumed the air contains sufficient entrained moisture and oxygen to enable pooling of liquid at low or especially cool locations and promote corrosion. The applicant evaluated this material and environment in Section C.1.2.6 of the application and identified several forms of corrosion that may result in loss of material (e.g., galvanic corrosion, pitting, crevice corrosion, microbiologically influenced corrosion (MIC), and selective leaching). However, in Table 3.2.4-1 of the application, the applicant identified only cracking due to thermal fatigue as an applicable aging effect. Discuss why loss of material is not an applicable aging effect for copper alloys exposed to a humid air environment.

RESPONSE TO RAI 3.4-CRD-1:

Nondried or humid air encompasses ambient air at various humidities. Based on operating conditions and experience, the air inside these CRD valve bodies is not wetted. Section C.1.2.6 identified loss of material as an aging effect for various components in nondried gas environments. For loss of material to occur in copper alloy components, generally, sufficient moisture to enable pooling of liquid must be present. This condition is not present in the subject CRD valves. Therefore, as noted in LRA Table 3.2.4-1, loss of material is not an aging effect requiring management for these valves.

RAI 3.4-CRD-2:

The applicant's gas systems component inspections program consists of one-time inspections of 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 applicant credits this program for aging effects of copper alloy valve bodies. Clarify whether these particular components fall within the scope of this AMP. The staff notes also that no AMPs were identified for copper valve bodies in Table 3.2.4-1 of the application, although the associated commodity group C.2.2.9.3 references this program. Resolve this discrepancy.

RESPONSE TO RAI 3.4-CRD-2:

Commodity group C.2.2.9.3 includes copper alloy components with a humid or wetted gas environment. A further distinction is made, as discussed in the response to RAI 3.4-CRD-1, between conditions where pooling of liquid does occur and where pooling does not occur. Commodity group C.2.2.9.3 includes components meeting both of these conditions.

For example, brass valve bodies in a nondried or humid air environment provide a pressure boundary function for the emergency diesel air start system (R43). Based on operating experience, some pooling of moisture can occur. Therefore, these valve bodies are subject to loss of material, for which the GSCI is credited (see LRA Table 3.2.4-12). On the other hand, the brass valve bodies which support the CRD intended functions (C11) are not in a wetted air environment where pooling of moisture will occur, and therefore, are not subject to loss of material as noted in Table 3.2.4-1.

Thus, Section C.2.2.9.3 refers to the GSCI as the AMP for the brass valves performing the pressure boundary for the emergency diesel air start system. This section also includes the CRD valves (C11), but only for cracking, which is managed by TLAA.

RAI 3.4-DPS-1:

The drywell pneumatics system supplies the motive gas to various equipment inside the drywell. Section 2.3.4.11 of the application provides the description of this system and states the following: "A major portion of the drywell pneumatic system is primarily obsolete and not currently used. The control air is supplied from the nitrogen makeup system or instrument air. The system components still exist . . . but are isolated by valve alignment or the lines are physically cut and capped." Based on this description, it is not clear to the staff which components are supplied the control air from the nitrogen makeup system or instrument air. Resolve this discrepancy and provide the basis for supplying control air to an obsolete portion of this system whose lines are physically either cut or capped.

RESPONSE TO RAI 3.4-DPS-1:

The application text is meant to clarify that the compressor, aftercooler, separator, and dryer, as well as the 5-micron filter, shown on drawings HL-16286 and HL-26066 are obsolete and are not used. Plant Hatch has retired this equipment in place. The portion of the drywell pneumatic system that is obsolete is not highlighted on drawings HL-16286 and HL-26066, and is situated between valves F015 and F003. Control air is not supplied to the obsolete equipment. In fact, for Unit 1 (drawing HL-16286), this obsolete equipment is isolated – the lines are cut and capped. In Unit 2, the obsolete components are isolated through the locked closed valve F015 and the normally closed valve F003.

Refer to the boundary drawings for an illustration of the in-scope components. Also, refer to drawings HL-16299 and HL-28023 for an additional illustration of the in-scope components to which the drywell pneumatic system feeds motive gas.

RAI 3.4-FPS-1:

In Table 3.2.4-18 of the LRA, the applicant did not identify any aging effects for fire doors constructed from galvanized steel. Staff experience has been that galvanized steel can experience loss of material even under relatively benign conditions. Discuss your experience at Hatch with galvanized steel components. Justify your conclusion that loss of material is not an applicable aging effect for galvanized steel components.

RESPONSE TO RAI 3.4-FPS-1:

Galvanized steel exposed to an indoor air environment does not experience corrosion as an aging effect requiring management. Indoor temperatures and humidity are controlled within ranges that do not promote significant degradation of galvanized components. Many indoor galvanized steel components have shown little, if any, measurable degradation of the galvanized coating after over twenty years of operation.

As noted in LRA Section C.2.3.4.3, a review of the condition reporting database mentioned in Section 3.0 showed that approximately 1100 condition reports had been written on the in-scope fire doors. These condition reports were screened to determine those that might potentially be age related. These reports primarily noted conditions associated with active mechanisms (e.g., doorknobs, closers, etc.) due to mechanical use. No condition reports resulted from identified age-related degradation of the fire doors.

RAI 3.4-FPS-2:

The fire protection system has various components constructed from cast iron, aluminum, carbon steel, galvanized steel, copper alloy, and stainless steel exposed to raw water. The applicant evaluated the aging effects for these materials in raw water in Section C.2.3.1 of the application and identified loss of material caused by general corrosion, galvanic corrosion, crevice corrosion, pitting, and MIC; cracking caused by stress corrosion cracking, intergranular attack, and thermal fatigue; and flow blockage due to fouling as the aging effects. Clarify which materials are subject to which aging effects when exposed to raw water.

RESPONSE TO RAI 3.4-FPS-2:

The fire protection system components exposed to raw water, and the materials of construction, as well as the aging effects requiring management are itemized in the lists of LRA Table 3.2.4-18.

RAI 3.4-FPS-3:

The fire protection system has various components constructed from cast iron, copper alloy, aluminum, carbon steel, galvanized steel, and stainless steel exposed to an air environment. The applicant evaluated the effects of aging in Sections C.2.3.1, and C.2.3.3 and identified loss of material and cracking as the aging effects for these materials in an air environment. Clarify which materials are subject to which aging effects when exposed to an air environment.

RESPONSE TO RAI 3.4-FPS-3:

The fire protection system components exposed to an air environment, and the materials of construction, as well as the aging effects requiring management are itemized in the lists of LRA Table 3.2.4-18.

RAI 3.4-FPS-4:

The fire protection system has various components constructed from carbon steel, stainless steel, copper alloy, and cast iron exposed to fuel oil. The applicant evaluated the effects of aging in section C.2.3.2 of the application, and identified cracking due to thermal fatigue, stress corrosion cracking, and intergranular attack and loss of material due to general corrosion, galvanic corrosion, pitting, crevice corrosion, and MIC. Clarify which materials are subject to which aging effects when exposed to fuel oil.

RESPONSE TO RAI 3.4-FPS-4:

The fire protection system components exposed to fuel oil, and the materials of construction, as well as the aging effects requiring management are itemized in the lists of LRA Table 3.2.4-18.

RAI 3.4-FPS-5:

The fire protection system has various components constructed from carbon steel, galvanized steel, and copper alloy exposed to a carbon dioxide or dried air environment. The applicant evaluated the effects of aging in section C.2.3.3 of the application and identified loss of material due to general corrosion, galvanic corrosion, selective leaching, pitting, crevice corrosion, wear, and intrusion of waterborne agents; cracking due to thermal fatigue, stress corrosion cracking, and intergranular attack; and change in material properties due to compaction and settling, intrusion of waterborne agents, thermal effects, and material separation within thermal insulating materials. However, Table 3.2.4-18 only lists loss of material and cracking. Clarify this discrepancy.

RESPONSE TO RAI 3.4-FPS-5:

LRA Table 3.2.4-18 lists aging effects, not aging mechanisms. Section C.2.3.3 lists the aging mechanisms associated with the aging effects requiring management. Three aging effects requiring management (loss of material, cracking, and change in material properties) are identified in Section C.2.3.3, but numerous aging mechanisms are noted.

RAI 3.4-FPS-6:

Table 3.2.4-4 of the LRA states that access doors require the protective coatings program. Therefore, the staff believes that similar requirements may be needed for the carbon steel fire doors because of similarities in materials and environment. Discuss why the protective coatings program is not credited for aging management of carbon steel fire doors.

RESPONSE TO RAI 3.4-FPS-6:

The fire protection activities are credited with managing aging of fire doors. Surveillance of fire doors is performed once every six months. Visual inspections include documentation of the physical condition of the fire doors. Degradation of external coatings of fire doors will be detected by the fire protection activities and coatings problems will be corrected utilizing the protective coatings program as described in Appendix B, Section 2.3.

RAI 3.4-FPS-7:

To manage aging effects for cast iron, copper alloy, aluminum, carbon steel, galvanized steel, and stainless steel exposed to an air environment, the applicant relies on fire protection activities and the protective coatings program. However, Table 3.2.4-18 does not describe how the protective coatings program will be used to manage these aging effects. Are these components painted/coated similar to the cast iron and carbon steel components?

RESPONSE TO RAI 3.4-FPS-7:

Only carbon steel fire protection components have paint that is credited as a protective coating and managed by the protective coatings program. Cast iron, stainless steel, aluminum, copper alloy, and galvanized steel components do not require a protective coating in the applicable environments. Paint is inspected per the industry guidance referenced in Appendix B, Section 2.3, for the protective coatings program.

RAI 3.4-FPS-8:

For the fire protection system, you identified several components (e.g., nozzles, strainers, tanks) that have air as an environment. You cited in Table 3.2.4-18 of the LRA that the aging effects include flow blockage. In these instances, you also cite the commodity group as C.2.3.1. Clarify why flow blockage is a concern for components exposed to an air environment. It is not discussed in C.2.3.3. Also, clarify why you reference commodity group C.2.3.1 when this commodity group discusses water environments as opposed to C.2.3.3, which discusses gas environments.

RESPONSE TO RAI 3.4-FPS-8:

Flow blockage is not a concern for components exposed to an air environment. Flow blockage was inadvertently placed in Table 3.2.4-18 as an aging effect for nozzles, strainers, and tanks in the fire protection system. Section C.2.3.1 discusses water based fire suppression systems that contain both water filled components and air filled components. Examples of air filled components are dry pipe sprinkler system headers and spray nozzles. The fire water storage tank contains both water and air such that two internal environments exist in association with one component. Section C.2.3.3 discusses compressed gas based fire suppression systems. The gas is CO_2 (Halon has been removed from the scope of license renewal - see the response to RAI 2.3.4-FPS-5). CO_2 is a dried gas, not atmospheric air, and the aging effects are different from those for air. Therefore, Section C.2.3.1 is referenced because it contains both water-filled and air-filled components, and C.2.3.3 is not referenced because it contains dry gas filled components only.

RAI 3.4-FPS-9:

Table 3.2.4-18 references commodity group C.2.3.1, "Evaluation of Water Based Fire Suppression Systems" for fusible material, bulbs and links exposed to an inside environment. However, this commodity group discusses aging effects for water and gas environments, not an inside environment. Clarify the aging effects for these materials exposed to an inside environment. Similarly, the table references commodity group C.2.3.3 for organic insulation materials. This commodity group discusses aging effects for dried or wetted gas environments, not an inside environment. Clarify the aging effects for this material exposed to an inside environment. Finally, Table 3.2.4-18 cites cracking and change in material properties as aging effects for kaowool hold down straps and references commodity group C.2.3.4.3. There is no discussion of this material or these aging effects in this commodity group. Resolve this discrepancy.

RESPONSE TO RAI 3.4-FPS-9:

See LRA Section C.1.2.8 for a definition of "inside" environment. In brief, "Inside" is the external component environment for components sheltered from the weather. Sprinkler head fusible links (fusible material), and sprinkler head bulbs are components of the water-based fire suppression system of Section C.2.3.1. All in-scope sprinkler heads are located in a building or structure, and hence the "inside" environment applies. The aging effects are loss of material and cracking for lead alloy fusible links, and cracking for copper fusible links and glass bulbs. Loss of material is not an aging effect for copper sprinkler head links, and was inadvertently placed in Table 3.2.4-18.

The organic insulation material is applicable to CO_2 storage tank insulation that can be located in either the "inside" or "outside" environment. See Section C.1.2.9 for a definition of "outside" environment, and Section C.2.3.3 for compressed gas based fire suppression systems. In brief, "outside" is the external environment for a component outside a structure that would offer protection from the weather. CO_2 tank insulation is located in both of these environments. The aging effects are cracking, loss of material, and change in material properties. Loss of material is an aging effect for tank insulation, and was inadvertently left out of Table 3.2.4-18. The "outside" environment also applies to tank insulation, and was inadvertently left out of Table 3.2.4-18.

The correct commodity group reference is C.2.3.4.2, not C.2.3.4.3, which was inadvertently placed in Table 3.2.4-18. Section C.2.3.4.2 applies to Kaowool cable tray wrap material and the galvanized steel hold-down straps. The aging effects for Kaowool are cracking, loss of material, and change in material properties. There are no aging effects for galvanized steel hold-down straps in the inside environment. Loss of material was inadvertently left out of Table 3.2.4-18 for Kaowool and hold-down straps.

RAI 3.4-FPS-10:

Section C.1.2.6.2 of the LRA states that 140 °F is the minimum temperature needed for stress corrosion cracking to occur. Will any part of the FPS see temperatures this high? Discuss why cracking due to stress corrosion cracking or intergranular attack is a possible aging effect for water-based fire suppression systems as discussed in commodity group C.2.3.1.

RESPONSE TO RAI 3.4-FPS-10:

No part of the fire protection system is normally exposed to temperatures as high as 140 °F.

The aluminum components of the fire protection system, including the water based fire suppression systems, can experience SCC or IGA. SCC and IGA for the aluminum alloys of fire protection system components are not temperature sensitive; i.e., there is no temperature threshold below which these phenomena cannot occur. The temperature threshold of 140 °F for SCC and IGA applies to stainless steel commodities only. Therefore, cracking due to SCC or IGA is an aging effect requiring management for the aluminum alloys of the fire protection system.

Stainless steel components in the fire protection system are not subject to SCC or IGA because the temperature is below 140 °F. However, these components can be subject to cracking due to thermal fatigue.

In LRA Section C.2.3.1, cracking due to SCC and IGA applies to aluminum alloys, and cracking due to thermal fatigue applies to both aluminum alloys and stainless steel.

RAI 3.4-FPS-11:

In Table 3.2.4-18, the applicant stated that tubing fittings may be exposed to fuel oil and raw water environments and references commodity group C.2.3.1, which is a discussion of the AMR of water-based fire suppression systems. Discuss why a second commodity group, C.2.3.2 is not referenced for this component grouping and why diesel fuel oil testing is not included as an AMP for these components, consistent with other components exposed to fuel oil. For these same tubing fittings, clarify which materials are exposed to just raw water and which are exposed to just fuel oil, if such a distinction exists.

RESPONSE TO RAI 3.4-FPS-11:

Commodity group C.2.3.2 should also be referenced for the components identified in the RAI. In addition, diesel fuel oil testing is an applicable AMP. These items were inadvertently omitted from Table 3.2.4-18. Copper, copper alloys, and cast iron materials are exposed to both raw water (water based fire suppression system) and fuel oil (fire protection diesel fuel oil supply system).

RAI 3.4-FPS-12:

You identified elastomers as fire penetration seal materials in Table 3.2.4-18, "Aging Effects Requiring Management for Components Supporting Fire Protection System," of the license renewal application. However, you did not discuss a need for an AMP for this component type in Appendix C.2.3.4.1. Provide the following information to justify the lack of an AMP for elastomers:

a. Indicate the temperature under which the cracking of elastomers due to thermal exposure is not an applicable aging effect and provide the technical bases (e.g., technical references) for the threshold values for the temperature.

b. Provide a description of the applicable site-specific operating history and include occurrences of observable seepage or leaching through concrete walls below grade, which would be indicative of degradation of waterstops, waterproofing membranes, caulking, and/or sealants.

c. Because seepage through these materials has been previously identified in other nuclear power plant structures, which is indicative of elastomer aging, provide a technical justification for not identifying aging that is applicable to elastomers.

d. If such conditions exist at Hatch, provide an AMR for the affected items or explain why such a review is not required.

RESPONSE TO RAI 3.4-FPS-12:

As noted in the RAI, elastomers are identified in LRA Table 3.2.4-18 as materials contained in fire penetration seals. Appendix C.2.3.4.1 characterizes the elastomer as silicon rubber foam. The following specific responses to parts a - d of the RAI are provided:

a. See LRA Section C.2.3.4.1. Also, see Appendix B, Section 2.1, for a discussion of the aging management for elastomers used in fire penetration seals.

b. A review of building operating history for the past five years, and maintenance work orders for the past 15 years, indicates that no seepage or leaching has been detected at Plant Hatch through concrete walls below grade. There are no fire penetration seals located in below grade walls.

c. As noted in b., above, there are no fire penetration seals located in below grade walls. Therefore, elastomer aging in penetration seals located below grade is not applicable.

d. Elastomers utilized as fire penetration seal materials at Plant Hatch and requiring aging management are discussed in LRA Appendix C.2.3.4.1. Fire protection activities are credited with aging management of fire penetration seals. Also, see the response to part a., above.

RAI 3.4-FPS-13:

Table 3.2.4-18 and Appendix C.2.3.4.3 of the application refer to the fire protection system. Previous applications have identified masonry block walls as fire protection barriers. However, cracking for masonry block walls in the auxiliary building was not identified for an AMR. Provide the following information to justify not performing an AMR for the masonry block walls in the auxiliary building:

a. Identify the masonry walls and the applicable intended functions that are included within the scope of license renewal and therefore are subject to an AMR.

b. Identify any masonry walls at Plant Hatch that are included within the scope of IE Bulletin 80-11, "Masonry Wall Design" and USI A-46, "Seismic Qualification of Equipment in Operating Plants" and that are within the scope of license renewal and subject to an AMR. Provide a justification for excluding any of these walls from an AMR.

c. If Hatch does have an AMP for the auxiliary building masonry walls (although the staff could not identify such an AMP through its review of the fire protection system), describe how this program incorporates the insights provided in Information Notice (IN) 87-67, "Lesson Learned from Regional Inspection of Licensee Actions in Response to IE Bulletin 80-11".

RESPONSE TO RAI 3.4-FPS-13:

There is no auxiliary building at Plant Hatch. The fire barrier function of masonry block walls is included in Table 2.4.5-1. This component function has also been identified for all masonry block walls that may be located in the systems in LRA Section C.2.6.1. Masonry block walls related to fire protection are also found in the control building and at the main stack.

Masonry block was inadvertently left out of the "Materials" column in Tables 2.4.11-1, 3.3.1-11, 2.4.13-1, and 3.3.1-13. Also, "Fire Barrier" in the Component Functions column was left out for the same tables. Masonry block walls in the turbine building (U29) are not in scope, and hence should not have been in the materials column in Tables 2.4.8-1 and 3.3.1-8.

See the response to RAI 3.6-47 for the response to parts b. and c. of this RAI.

RAI 3.4-IA-1:

The description of the instrument air system in section 2.3.4.9 of the application is confusing. The applicant discusses instrument air, drywell pneumatic system and the compressed air system. Clarify the scope of these three systems and clarify the specific scope of the instrument air system.

RESPONSE TO RAI 3.4-IA-1:

The text in LRA Section 2.3.4.9 describes the instrument air system for Plant Hatch. However, because the LRA addresses intended functions, the compressed air system and the drywell pneumatic system must be discussed along with instrument air. During normal operation, the nonsafety-related compressed air system charges the nonsafety-related instrument air system. Portions of the instrument air system are made non-interruptible by valves that close automatically upon loss of header pressure. A connection can be made (through a normally removed spool piece) between the non-interruptible portion of the instrument air system and the drywell pneumatic system.

However, the compressed air system (P51) has no intended function within the scope of the Rule.

The in-scope intended function that includes the instrument air system for Plant Hatch is P52-01 (Non-Interruptible Instrument Air Supply). This function provides motive force for certain air-operated valves so they can be available following certain events where the compressed air system is lost. For clarification of these events, see Chapter 15 of the Plant Hatch Unit 2 FSAR. FSAR Chapter 15 states that the instrument air system is not safety related, but that it is operationally convenient to have a small set of air operated valves available to respond to the events. A discussion of these air systems can also be found in Unit 1 FSAR Section 10.11 and Unit 2 FSAR Section 9.3.1.

The equipment necessary to assure the P52-01 intended function includes accumulators (usually filled with nitrogen), and the piping and check valves necessary to feed the air operators, and to isolate the accumulators from the rest of the instrument air system. Because the air accumulators normally supplied from P52 are of a design very similar to those normally supplied from P70 (including the material and internal environment), SNC has chosen to lump all the in-scope accumulators into the P52-01 function. The accumulators located inside the drywell interface directly with the drywell pneumatic system (with intended function P70-01), and are backed up with the non-redundant nitrogen supply from the nitrogen storage tank (intended function T48-01). The drywell pneumatic system has the intended function (P70-01) of nitrogen supply to the SRVs and MSIVs that are located inside the drywell.

RAI 3.4-IN-1:

Table 3.2.4-3 of the application describes three aging effects for stainless steel insulation jacketing exposed to an inside environment: loss of material, cracking and change in material properties. The associated commodity group, C.2.4.4.2 discusses only loss of material and cracking. Clarify this discrepancy.

RESPONSE TO RAI 3.4-IN-1:

The aging effect "change in material properties" does not apply to stainless steel insulation jackets, and was inadvertently placed in Table 3.2.4-3.

RAI 3.4-PSW-1:

The plant service water (PSW) and residual heat removal service water inspection program is a condition monitoring program designed to detect wall thickness degradation or fouling in the PSW system. The description of this inspection program is provided in A.1.13 of the application. It is not clear from this description that all of the mechanical components in the system which credits this inspection program are within the scope of the inspection program. Confirm that the following PSW system mechanical components are included within the scope of this inspection program: flexible connector, pump bowl assembly, pump discharge column and head, restricting orifices, sight glass bodies, strainers, strainer baskets, thermowells, valve bodies, and venturi.

RESONSE TO RAI 3.4-PSW-1:

The components identified in this RAI are included within the scope of the PSW and RHRSW inspection program. See Tables 3.2.3-2 and 3.2.4-7 for a list of these components and the applicable aging management program. See section C.2.2.6.1 and C 2.2.6.2 for the AMR for these components. Also, see Appendix B, Section 1.13 for the program description.

RAI 3.4-PSW-2:

In commodity group C.2.2.6.3 of the application, the applicant credits the PSW and residual heat removal system inspection program for managing the aging effects on copper alloys in the river water environment. However, Table 3.2.4-7 of the LRA does not list this inspection program as an AMP for copper alloy valve bodies. Resolve this discrepancy.

RESPONSE TO RAI 3.4-PSW-2:

Section C.2.2.6.3 provides the AMR for copper components included in two systems – RHRSW and PSW – subjected to river water environment. Copper tubing provides a pressure boundary function for the RHRSW system function (E11-01), and is shown in Table 3.2.3-2. Brass valve bodies also provide a pressure boundary function for the PSW system (P41) as shown in Table 3.2.4-7. Both commodities credit the PSW and RHRSW inspection program for managing the aging effects. Table 3.2.4-7 has been revised to take credit for the PSW and RHRSW inspection program managing the aging effects of copper alloys in river water environment. This revision was provided to the NRC by electronic communication on April 19, 2000.

RAI 3.4-PSW-3:

The structural monitoring program provides condition monitoring and appraisal of certain important structures and structural components. The description of this inspection program is provided in A.2.5 of the application. It is not clear from this description that all of the mechanical components in the PSW system which credits this monitoring program are within the scope of the inspection program. Clarify whether the aging effects of the following PSW mechanical components are managed by the structural monitoring program: flexible connector, piping, pump bowl assembly, pump discharge column and head, restricting orifices, sight glass bodies, strainers, strainer baskets, and venturi.

RESPONSE TO RAI 3.4-PSW-3:

The only aging effect managed by the SMP for the PSW system, as listed in the LRA, is flow blockage due to silt and debris intrusion into the system components such as those listed in Table 3.2.4-7. This aging effect is managed by periodic inspection and removal of accumulated silt and debris from the intake structure pump suction pit. These pit inspection and diving activities that are listed in the LRA as part of the SMP, however, are now part of the PSW and RHRSW inspection program. This change, subsequent to the LRA submittal, was made to better associate these activities with the PSW system. See Appendix B, Section 1.13, for the description of the PSW and RHRSW inspection program, which includes the intake structure pit inspection and diving activities.

RAI 3.4-PSW-4:

The aging effects of PSW carbon steel components in the river water environment is further managed by galvanic susceptibility inspections. Section A.3.1 of the application describes this inspection program as a condition monitoring program. This monitoring program is a one-time inspection which will provide objective evidence that galvanic susceptibility is being managed for specific components within the scope of license renewal. However, in Table C.2.2.6-1 of the LRA, this program is said to provide for periodic inspections of carbon steel components. Resolve this discrepancy.

RESPONSE TO RAI 3.4-PSW-4:

Table C.2.2.6-1 inadvertently states galvanic susceptibility inspections as periodic. Galvanic susceptibility inspections are one-time inspections.

RAI 3.4-PSW-5:

In Section C.2.2.6.1 of the LRA, the applicant credits the galvanic susceptibility inspection program to manage the aging effects of carbon steel components in the river water environment. The carbon steel components crediting this program include valve bodies, strainer bodies, sight glass bodies, thermowells, pump discharge columns and pump discharge heads. However, Table 3.2.4-7 of the LRA does not list this inspection program as an AMP for these plant service water carbon steel components. Resolve this discrepancy.

RESPONSE TO RAI 3.4-PSW-5:

LRA Table 3.2.4-7 includes the galvanic susceptibility inspections for carbon steel piping and valve bodies. LRA Appendix C.2.2.6.1 is a discussion of the commodity group representing carbon steel components in a river water environment. Thus, it is appropriate in this Appendix C.2 section, as for all commodity group discussions, to address all programs that apply to one or more of the components that comprise the commodity group. The LRA is not read to mean that <u>all</u> programs listed in a C.2 section apply to <u>all</u> components associated with the commodity group. That information is contained in the various Section 3 tables that have components belonging to the subject commodity group.

RAI 3.4-PSW-6:

For the PSW system, the applicant refers to commodity group C.2.2.6 for discussion of the aging effects and AMPs. For all four subgroups in this commodity group, the applicant references the PSW and residual heat removal service water inspection program, the PSW and residual heat removal service water chemistry control program, and the structural monitoring program to manage these aging effects. In addition, the galvanic susceptibility inspection was a fourth program for carbon steel components exposed to raw water. However, in Table 3.2.4-7, the applicant does not consistently refer to these programs. For example, the carbon steel pump discharge column, pump discharge head, sight glass body, strainer, and thermowell, do not reference the galvanic susceptibility inspections. The applicant takes credit for these inspections in the commodity group discussion. Clarify these discrepancies. Also, the structural monitoring program also appears to be inconsistently applied. Clarify the scope of this program and how it interfaces/overlaps/complements the PSW and residual heat removal service water inspections.

RESPONSE TO RAI 3.4-PSW-6:

See the response to RAIs 3.4-PSW-3 and 3.4-PSW-5. The SMP was inadvertently left out of Table 3.2.4-7 for two components - CS thermowell, and SS thermowell. However, this activity (pit diving) is now part of the PSW and RHRSW inspection program, which is referenced in the table.

RAI 3.4-RBHVAC-1:

Section A.3.3 of the license renewal application, "Gas Systems Component Inspections" states that the sample population for this AMP will include gas bearing piping and ductwork. Does the sample population of ductwork in this AMP include the galvanized steel ductwork in the reactor building HVAC system?

RESPONSE TO RAI 3.4-RBHVAC-1:

Galvanized steel ductwork for the reactor building HVAC system (T41) is included in the sample population for the GSCI. Refer to Appendix B, Section 3.3, for the sampling criteria used in the GSCI.

RAI 3.4-RE-1:

The refueling equipment system has bolting components yet the applicant did not identify loss of preload as an applicable aging effect for this system and these components. Discuss why loss of preload is not an applicable aging effect for this particular system.

RESPONSE TO RAI 3.4-RE-1:

The AMR of the refueling equipment determined that loss of bolt and anchor preload does not require aging management.

Bolts and anchors for the refueling equipment were installed and inspected per vendor recommendations, and in accordance with plant procedures. No gaskets are used in these structural connections. Per 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. Except for the reactor building crane rails, the refueling equipment, bolts and anchors are not subject to high temperatures, high displacement vibration loading, or high stress vibration loading. As discussed in the response to RAI 3.6-9, local degradation of concrete surrounding anchors because of vibratory loads is not an aging effect requiring management.

The anchor design for the reactor building crane rails allows the rails to move in one direction. The rails slide underneath plates that are held in place by anchors to the building structural steel.

RAI 3.4-RE-2:

The discussion in C.2.6.3 of the application states that the structural monitoring program will be applied to the refueling equipment system, yet the applicant does not credit this program in Table 3.2.4-2 of the application. Resolve this discrepancy.

RESPONSE TO RAI 3.4-RE-2:

LRA Appendix C.2.6.3 is a discussion of the commodity group representing structural steel components in Seismic Category I buildings, the turbine building, and Category I yard structures. Thus, it is appropriate in this Appendix C.2 section, as for all commodity group discussions, to address all programs that apply to one or more of the components that comprise the commodity group. The LRA is not read to mean that all programs listed in a C.2 section apply to all components associated with the commodity group. That information is contained in the various Section 3 tables that have components belonging to the subject commodity group. Thus, there is no discrepancy in the information presented.

RAI 3.4-RE-3:

Provide the commodity group reference for the aluminum rivets in Table 3.2.4-2 of the application.

RESPONSE TO RAI 3.4-RE-3:

See LRA Section C.2.6.6 for a discussion of aging management for aluminum commodities. Note that the aluminum rivets in the refueling equipment system (F15) have no aging effects requiring management since they are exposed to air and are not susceptible to galvanic corrosion.

RAI 3.4-SS-1:

Discuss why the passive component inspection activities are not credited for the stainless steel components in Table 3.2.4-6 when it is credited in the associated commodity group C.2.2.9.2 of the license renewal application.
RESPONSE TO RAI 3.4-SS-1:

Based upon the normal operating temperature of the stainless steel components in Table 3.2.4-6 (< 140 °F), SCC is not an aging effect requiring management. Cracking due to thermal fatigue is managed for these components by a TLAA. Loss of material, if present, is not likely to be aggressive in nature. Thus, SNC conservatively chose to manage the aging in these valves through the GSCI. Also, see the response to RAI 3.4-CBHVAC-1.

RAI 3.4-TSR-1:

To manage corrosion-induced aging effects for the carbon steel traveling screens submerged in raw water, the applicant relies on the structural monitoring program, as identified in Table 3.2.4-16 of the LRA. The applicant references commodity group C.2.6.3 for this component. This commodity group states that the protective coatings program is also applicable. Discuss why this system does not rely on a preventative measure such as protective coatings for the carbon steel traveling screen. This response should also clarify the discrepancy between Table 3.2.4-16 and commodity group C.2.6.3.

RESPONSE TO RAI 3.4-TSR-1:

LRA Appendix C.2.6.3 is a discussion of the commodity group representing structural steel components in Seismic Category I buildings, the turbine building, and Category I yard structures. Thus, it is appropriate in this Appendix C.2 section, as for all commodity group discussions, to address all programs that apply to one or more of the components that comprise the commodity group. LRA Table 3.2.4-16 references commodity group C.2.6.3 for the AMR of the carbon steel and stainless steel materials of the travelling screen, and notes aging effects for the component are managed by the SMP. The table is not read to mean that all programs listed in a C.2 section apply to all components associated with the commodity group. That information is contained in the various Section 3 tables that have components belonging to the subject commodity group. Thus, there is no discrepancy in the information presented in Table 3.2.4-16 and Appendix C.2.6.3.

Some traveling screen parts are furnished with protective coatings to protect them from the river water and outside environments to which they are subjected. However, the protective coatings program is not credited to manage aging effects for these items. The screen is comprised of a stainless steel mesh.

The SMP is credited with aging management of the traveling screen. If significant corrosion or wear is detected during SMP inspections, the results are documented and reported for follow-up action as required. See Appendix B, Section 2.5, for the inspection frequency for the intake structure, including the traveling screens.

RAI 3.4-TSR-2:

For the traveling water screens/trash rack system, flow blockage is not an applicable aging effect as shown in Table 3.2.4-16 for most of the components. This is consistent with the commodity group discussion in C.2.6.3 but it is not consistent with the aging effects in other raw water systems such as the PSW system. Discuss why flow blockage is not an applicable aging effect for this system.

RESPONSE TO RAI 3.4-TSR-2:

PSW system components are subject to flow blockage due to aging mechanisms such as fouling, corrosion product buildup, and silting. By design, the traveling water screens and trash racks are not subject to these mechanisms. Since the function of these components is to screen out large debris, large passages are provided that minimize the potential for blockage, and the spray wash feature keeps the screens free of debris accumulation. Review of plant operating history has not identified flow blockage as a concern for the traveling water screens/trash rack system. Therefore, flow blockage is not an applicable aging effect for trash racks and traveling water screens.

STEAM AND POWER CONVERSION SYSTEMS

RAI 3.5-EHC-1:

Section 2.3.5.1 of the LRA, stated that the purpose of the electro-hydraulic control (EHC) system is to provide control of reactor pressure during reactor startup, power operation, and shutdown. EHC also provides the means to control main turbine speed and acceleration during turbine startup and also protect the main turbine from undesirable operating conditions by initiating alarms, trips, and runbacks. The LRA also stated that EHC regulators 1N11-N042A/B and 2N32-N301A/B are included within the scope of license renewal. However, the regulators are not included with the mechanical components listed in the Table 2.3.5-1 of the LRA. Provide a complete list of all EHC mechanical components requiring an aging management review that are associated with the pressure control unit, speed control unit, desired load control unit, valve control unit, hydraulic power unit, and emergency trip system. Also, provide in the LRA Table 3.2.5-1, pertinent details of the aging management programs for the identified components.

RESPONSE TO RAI 3.5-EHC-1:

The regulators are active instruments, do not require an AMR, and should not have been included in LRA Table 2.3.5-1. Since the only in scope part of EHC is that portion needed to supply a backup pressure regulator, none of the components associated with the pressure control unit, speed control unit, desired load control unit, valve control unit, and hydraulic power unit are in scope. Components not in-scope are not subject to AMR. Any in-scope component subject to AMR that is associated with emergency trip systems is included in function C71-01 or C71-02, and presented in Table 2.5.15-1. Table 3.2.5-1 contains pertinent details of AMPs for the components supporting intended function N32-02 subject to AMR.

RAI 3.5-MC-1:

In Section 2.3.5.2 of the LRA, Table 2.3.5.2 of the LRA, Table 2.3.5-2, stainless steel piping is identified as one of the mechanical components requiring an aging management review. However, in Table 3.2.5-2 of the LRA, two different commodity groups C.2.2.1.1 and C.2.2.1.2 have been identified for the aging management of the stainless steel piping component which is stated to perform the same function and is under the same environment. Provide a rationale for evaluating this component under two separate commodity group.

RESPONSE TO RAI 3.5-MC-1:

Row four of Table 3.2.5-2, "Piping/C2.2.1.1, stainless steel" should be disregarded. The row was inadvertently not removed. The correct stainless steel piping reference is contained in row five.

RAI 3.5-MC-2:

In Table 3.2.5-2 of the LRA, bolting is identified as requiring an aging management review for components supporting main condenser system intended functions and their component functions. Appendix C commodity group C2.2.10.1 is identified for loss of pre-load aging effects due to embedment, gasket creep, thermal effects, and self-loosening. Self-loosening is described in Section C.1.2.7.2 to be caused by vibration, flexing of the joint, cyclic shear loads, and thermal cycles. In light of this, it is possible that some pipe cracking may be caused by the vibratory and/or cyclic aging effects within the main condenser system. Provide the cause of cracking identified in Table 3.2.5-2 and identify (if any) the most critical components and locations that experience dynamic fatigue aging effects requiring aging management.

RESPONSE TO RAI 3.5-MC-2:

The aging effect of cracking shown in Table 3.2.5-2 is due to thermal fatigue and SCC. Cracking due to vibration fatigue is not an aging effect requiring management for bolting in the main condenser system. The amount of preload prescribed for a bolted connection includes a vibration component. The torque activities AMP determines the amount of preload for the bolted connections. Cracking of pipe welds due to vibration is prevented by design. Nonconforming design or installation problems, if present, occur soon after the welds are made or a re-configured system is brought into service. Thus, cracking of pipe welds due to dynamic effects is a design and installation issue, not an aging effect requiring management.

STRUCTURES

RAI 3.6-1:

Referring to page A.1-17, Section A.1.14, "Primary Containment Leakage Testing Program," you stated that your program applies to all 10 CFR 50 Appendix J, Option B leakage rate testing requirements for systems, structures, and components within the scope of license renewal. Provide a summary discussion of the key elements of the above testing program and describe specifically how the intent of regulatory positions C1 through C4 of Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," are implemented in your program. If exceptions to these positions were taken by your testing program, please provide the basis for these exceptions.

RESPONSE TO RAI 3.6-1:

See the response to RAI 3.1.14-1.

RAI 3.6-2:

Referring to the third paragraph in Section A.1.14.1, "Description" on page A.1-17, you stated that "Type A tests are performed in accordance with ANSI/ANS 56.8, 1994 and/or Bechtel Topical Report BN-TOP-1 and implemented through plant procedures." Please explain the extent to which you intend to adopt the provisions of the referenced ANSI/ANS standard/report by your Type A test program. Also, clarify if the provisions that you 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, list those BN-TOP-1 provisions that are less stringent than those of ANSI/ANS 56.9-1994 and reconcile the differences.

RESPONSE TO RAI 3.6-2:

Presently, Type A 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 FSAR, 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." Regulatory Guide 1.163 endorses NEI 94-01, which states in Section 1.1, "Generally, a FSAR describes plant testing requirements, including containment testing. In some cases, FSAR 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." No formal comparison of ANSI/ANS 56.8-1994 with BN-TOP-1 has been performed at this time.

RAI 3.6-3:

In Section C.2.6.4, "Aging Management Review for Component Supports" of the Hatch LRA, it is stated that the SMP (A.2.5) provides for the visual inspection of component supports on a scheduled basis. However, in A.2.5, "Structural Monitoring Program," no detailed information is provided for relevant aging effects and the corresponding management programs, for the in-scope structures and components and their supports. The staff requests the applicant to revise A.2.5 to include a discussion of the aging effects of general corrosion of structural steel, including piping supports, cable raceway supports, HVAC duct supports, and equipment supports.

RESPONSE TO RAI 3.6-3:

LRA Section A.2.5 indicates that the SMP will be enhanced to include visual inspection of all of the components noted in this RAI, as well as for conduits and their supports, and panels, racks and their supports. The aging effect of loss of material due to general corrosion of structural steel includes the corrosion effects on supports for piping, cable raceways, HVAC ducts and equipment. Detailed information on the aging effects, and monitoring of the aging effects, is included in LRA Section C.2.6.3. Also, the existing SMP inspection guidelines and acceptance criteria for structural steel will be used to evaluate these components. This program document has been reviewed and approved by the NRC in association with Maintenance Rule implementation. A copy of this document is available for review.

Additional information on the SMP may be found in Appendix B, Section 2.5.

RAI 3.6-4:

Since the effects of loadings from rotating/reciprocating machinery may cause degradation of the steel load path and cracking of the concrete in the vicinity of the equipment anchorages, address the aging effects caused by such vibratory loading. The applicant should address the necessary criteria and attributes for an acceptable AMP for this mechanism.

RESPONSE TO RAI 3.6-4:

See the response to RAI 3.6-9.

RAI 3.6-5:

Since the effects of loadings from seismic, hydraulic or water hammer, and thermal expansion, may cause loss of weld integrity, loosening of bolted connections, displacement or misalignment of components, and cracking of concrete, address the aging effects caused by such loadings, for hangers and supports for ASME and non-ASME piping, tubing, and ducts, listed in Table 3.3.1-1 of the application. The applicant should address the necessary criteria and attributes for an acceptable AMP.

RESPONSE TO RAI 3.6-5:

Low-cycle and high-cycle fatigue due to thermal and mechanical loading was considered in the original design of steel components (piping, tubing and ducts) and their supports. If the components or supports were determined to be subject to repetitive loadings, which could cause fatigue, the design considered the number of stress cycles, expected stress range, and the type and location of the component or support. The piping supports may be subject to high-cycle vibration but the stress levels and vibration amplitudes are low. Seismic events are an example of event-driven loadings, and produce no aging effects requiring management. Piping systems subjected to shock type loadings employ components such as snubbers, struts, and spring devices that attenuate vibratory loadings. Flex connectors are installed in the ducting to isolate the ductwork and supports from machinery vibration. The plant site is located in an inactive seismic area (Unit 1 FSAR Section 2.5.6). Over a 60-year operating period, the plant will be subjected to very few, if any stress cycles from earthquakes. The building settlement curves (Unit 2 FSAR-Figure 2A-17 and 2A-18) began to flatten out by 1978 and have remained essentially flat, indicating that no subsequent measurable settlement has occurred. Therefore, it was determined that cracking (i.e., loss of weld integrity) of hangers and supports, due to low-cycle and high-cycle fatigue or distortion, does not require aging management.

For loosening of bolted connections and cracking of concrete see the response to RAI 3.6-9.

RAI 3.6-6:

The applicant identified loss of material as the aging effect for carbon steel and possibly galvanized steel in Table 3.3.1-1. It is not clear if galvanized steel is included for loss of material. Please confirm that galvanized steel is included for loss of material aging effect. If not, justify its exclusion.

RESPONSE TO RAI 3.6-6:

Loss of material is an aging effect for galvanized steel as shown on LRA Table 3.3.1-1. Also, see the response to RAI 3.6-8.

RAI 3.6-7:

Table 3.3.1-1, "Aging Effects Requiring Management for Components Supporting Piping Specialties Intended functions and Their Component Functions" of the Hatch LRA does not list piping insulation material as a submaterial under piping support requiring an AMR. The staff believes that insulation is within the scope of license renewal and subject to an AMR. In order for the staff to understand the basis for not including the insulation in Table 3.3.1-1, provide the following information:

a. As applicable, discuss the extent of usage of insulation materials in Hatch structures and component supports.

b. Intended function(s) associated with these insulation materials and the technical basis for its exclusion from the scope of Table 3.3.1-1

c. Discuss if the aging effects and the AMPs associated with steel component supports are applicable to the insulation materials. If so, identify the attributes monitored to detect the aging associated with the materials.

d. As applicable, discuss potential aging of steel components and their supports due to contact with these insulation materials.

e. Can application of the insulation materials reduce or compromise the effectiveness of AMPs credited with managing the aging of the insulated steel structural components (e.g., render component inaccessible for inspection)? If so, how does the credited AMP compensate for this potential concern?

RESPONSE TO RAI 3.6-7:

The insulation function is covered under L36-02. The in-scope insulation, applicable aging effects, and intended function of insulation for Plant Hatch are discussed in LRA Sections 2.3.4.3, A.2.4, C.1.2.11, and C.2.4.4. The components, component functions, environments, materials, aging effects, and aging management program for piping and equipment insulation are tabulated in Table 3.2.4-3. Aging of insulation is managed by the equipment and piping insulation monitoring program, which is described in Appendix B, Section 2.4. The installation of insulation will not reduce or compromise the effectiveness of AMPs credited with managing aging effects.

RAI 3.6-8:

Conduits, raceways, and trays are fabricated from either carbon steel, galvanized steel, or aluminum exposed to an inside containment environment. The applicant identified loss of material as the aging effect for carbon steel and possibly galvanized steel in Table 3.3.1-2. Please confirm that loss of material is considered as an aging effect for galvanized steel. If not, justify its exclusion.

RESPONSE TO RAI 3.6-8:

Galvanized steel exposed to an inside 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.

Section C.1.4.1 of the Plant Hatch 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.

RAI 3.6-9:

Table 3.3.1-2, "Components Supporting Cable Trays and Supports" of the LRA identifies loss of material due to corrosion of carbon steel and galvanized steel. You discussed aging effects for the loss of materials in the LRA, Appendix C, Section 2.6.4, "Aging Management Review for Component Supports," and took credit for SMP and Protective Coating Program as an AMP. However, you did not identify that self-loosening of bolted connections due to vibration is 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. Provide the technical justification for not identifying loss of pre-load due to the effects of vibration on concrete surrounding expansion and undercut anchors.

RESPONSE TO RAI 3.6-9:

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. Structural bolts and anchors at Plant Hatch were installed and inspected per vendor recommendations and in accordance with plant procedures. Per 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. 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. 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.

The Class 1 seismic structures at Plant Hatch are designed in accordance with ACI 318-63. EPRI Report TR-103842, "Class 1 Structures Industry Report," Revision 1, 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% of the static strength, and the structures can resist extremely high cycles of loading in the low amplitude, low stress range. In addition, the 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 Plant Hatch 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.

RAI 3.6-10:

Table 3.3.1-3, "Aging Effects Requiring Management for Components Supporting Primary Containment Intended Functions and Their Component Functions," of the Hatch LRA, lists the in-service inspection program (ISI) as one of the programs to manage the aging effects of structural steel, steel bellows and vent pipe. Section A.1.9.3 of Appendix A discusses industry codes, standards and acceptance criteria adopted by the ISI program. Title 10 of the Code of Federal Regulations, Part 50 endorsed ASME Section XI, Subsection IWE Code with the condition that 10 CFR 50.55a(b)(2)(ix) provisions be complied with. The Hatch submittal is not clear regarding this requirement. Please confirm that your reference to the 1992 Edition of ASME Section XI, Subsection IWE Code with the 1992 addenda, as stated in the ISI program, includes the requirements of 10 CFR 50.55a(b)(2)(ix) or justify your exclusion of the 10 CFR 50.55a requirements.

RESPONSE TO RAI 3.6-10:

Section A.1.9.1 of the Plant Hatch LRA states, "The Inservice Inspection (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 at Plant Hatch." SNC complies with the requirements of 10CFR50.55a(b)(2)(ix). These provisions are contained in SNC's submittal to the NRC for the third ten-year ISI interval.

RAI 3.6-11:

Section C.2.6.2, "Aging Management Review for Steel Primary Containment and Internals," states that the Hatch 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 Part 50 endorsed ASME Section XI, Subsection IWE Code with the condition that 10 CFR 50.55a(b)(2)(ix) provisions be complied with. The Hatch submittal is not clear regarding this requirement. Confirm that both the scope and the detail of the inspection implemented in accordance with ASME Section XI Table IWE-2500-1 also complies with the requirements for 10 CFR 50.55a(b)(2)(ix). In accordance with NUREG-1611, "Aging Management of Nuclear Power Plant Containments for License Renewal," 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 to inaccessible areas. Accordingly, for the Hatch primary containment and internal structures, describe how the aging effects for inaccessible areas will be addressed.

RESPONSE TO RAI 3.6-11:

SNC 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 SNC's submittal to the NRC dated July 19, 2000.

Section C.2.6.2 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.

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.

RAI 3.6-12:

Section A.1.9.4 of the LRA states that loss of material, cracking, loss of pre-load, and loss of fracture toughness are the aging effects monitored by the Hatch Inservice Inspection Program. Provide a discussion of past Hatch experience with respect to managing and monitoring these aging effects, including your experience with the embedded shell and the sand pocket regions of the Hatch primary containment and the loss of pre-load for metal fasteners.

RESPONSE TO RAI 3.6-12:

A general discussion of operating experience related to the ISI program may be found in Appendix B, Section 1.9. The following is a discussion of operating experience relevant to the specific areas of concern in this RAI.

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. Inspections in the accessible area of the sand cushions have not shown any moisture buildup or corrosion.

Visual inspections include associated bolted connections to confirm connection integrity. No looseness of bolts or nuts has been detected that could be attributed to loss of preload.

RAI 3.6-13:

Table 3.3.1-3,"Aging Effects Requiring Management for Components Supporting Primary Containment Intended Functions and their Component Functions," 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. As such, provide the following information:

a. The primary containment shell welds have a pressure boundary intended function as well as a structural support intended function. Discuss why the containment attachment welds were not included in Table 3.3.1-3.

b. Describe the AMP that manages the aging of attachment welds to the primary containment shell plates consistent with the 10 elements in the Standard Review Plan (SRP) in sufficient detail to allow the staff to assess the adequacy of this program to manage the applicable aging effects and compare the inspection requirements of this AMP to the requirements of ASME Section XI, Subsection IWE. In addition, if the inspection requirements of this AMP are less stringent than those of Subsection IWE, then provide a technical justification for these differences.

RESPONSE TO RAI 3.6-13:

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. Therefore, welds were not singled out as a separate commodity or component and were not listed separately in Table 3.3.1-3.

The ISI program, described in Appendix B, Section 1.9, complies with Subsection IWE of Section XI of the ASME Code. The ISI program is the aging management program that manages aging of attachment welds to the containment pressure boundary, and is also addressed in LRA Section C.2.6.2 and Table C.2.6.2-1.

RAI 3.6-14:

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. From the application, it is not clear if any primary containment galvanized steel components are exposed to torus water. Please clarify whether any primary containment galvanized steel components are subject to the torus water environment and, as applicable, indicate the appropriate AMP.

RESPONSE TO RAI 3.6-14:

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 an SRV discharge. Galvanized carbon steel exposed to water may experience a loss of material due to corrosion. 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. These programs are further discussed in Appendix B, Sections 2.3 and 1.7.

RAI 3.6-15:

Table 3.3.1-3, "Aging Effects Requiring Management for Components Supporting Primary Containment Intended Functions and Their Component Functions," does not provide any information regarding the aging management, including surveillance requirements, for gears, latches, and linkages, of personnel hatches and penetrations. Identify where fretting and lockup of hinges, locks and closure mechanisms for personnel hatches is discussed in the Hatch LRA, or provide a technical justification for not considering fretting and lockup as applicable aging effects for these components. Provide a description of the AMP for the personnel hatches consistent with the 10 elements in the SRP in sufficient detail to allow the staff to assess the adequacy of this program to manage the applicable aging effects.

RESPONSE TO RAI 3.6-15:

Locks and closure mechanisms are active components, and are not subject to aging management review. 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 Section C.2.6.2 and Appendix A, and further discussed in Appendix B, Sections 1.9, 2.3, and 1.14.

RAI 3.6-16:

Are any elastomers used in Hatch that are within scope and subject to an AMR? If yes, discuss their applicable aging effects. Since seepage through elastomers has been previously identified in other nuclear power plant structures, which is indicative of elastomer aging, provide a description of the applicable, site-specific operating history and include any occurrences of observable seepage or leaching through concrete walls below grade, which would be indicative of degradation of water stops, waterproofing membranes, caulking, and/or sealants and, as applicable, describe the AMP for managing the aging of Hatch elastomers.

RESPONSE TO RAI 3.6-16:

See the responses to RAI 2.4-4, RAI 2.4-RB-3, and RAI 3.4-FPS-12 for a discussion of elastomers subject to an AMR. See the response to RAI 3.4-FPS-12 for a discussion of operating history regarding seepage or leaching through concrete walls below grade. The AMPs credited for managing the aging of elastomers requiring management are described in LRA Sections C.2.3.4.1, C.2.5.2, and C.2.6.7.

RAI 3.6-17:

Section C.2.2.6.3 and Table 3.3.1-3 of the Hatch LRA are not consistent. Table 3.3.1-3 does not include flow blockage as an aging effect, while Section C.2.2.6.3 does include flow blockage. Please resolve this apparent discrepancy.

RESPONSE TO RAI 3.6-17:

Section C.2.2.6.3 and Table 3.3.1-3 should not be consistent, because they are applicable to different systems and environments. Section C.2.2.6.3 applies to non-Class 1 copper alloys in the river water environment, whereas Table 3.3.1-3 applies to components supporting primary containment intended functions with various environments that do not include river water.

RAI 3.6-18:

In Table 3.3.1-3 of the LRA, it is noted that 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 are embedded. The application does not clearly indicate the materials that are embedded. Please provide such information.

RESPONSE TO RAI 3.6-18:

Table 3.3.1-3 grouped carbon steel, galvanized steel, and stainless steel bolt and anchor materials in one line item, with embedded as an environment. The miscellaneous steel group included carbon steel and galvanized steel, and listed embedded as an environment. Containment penetrations included carbon steel and stainless steel, and listed embedded as an environment. A review of screening records and supporting information identified carbon steel components, only, as embedded for the Table 3.3.1-3 items identified above.

RAI 3.6-19:

Several items in Table 3.3.1-3 of the Hatch LRA (e.g., anchors and bolts, miscellaneous steel, steel bellows) do not include cracking as an aging effect, while Section C.2.6.2, which is referenced by these items, does include this aging effect. Please clarify the discrepancy.

RESPONSE TO RAI 3.6-19:

Cracking identified as a detrimental aging effect in Section C.2.6.2 applies only to cracking due to fatigue of the torus. Anchors and bolts, and miscellaneous steel are not subjected to significant vibratory or cyclic loads, and are therefore not subject to cracking. 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.

RAI 3.6-20:

Table 3.3.1-4, "Aging Effects Requiring Management of Components Supporting for Fuel Storage Intended Functions and Their Component Functions," of the LRA identifies loss of material as an aging effect for the aluminum restraints in the spent fuel pool (SFP) demineralized water. You discussed the loss of material due to galvanic corrosion, crevice corrosion, pitting, and micro-biologically influenced corrosion in the LRA, Appendix C, Section 2.6.6, "Aging Management Review for Aluminum," and took credit for Fuel Pool Chemistry Control as an AMP; however, Table 3.3.1-4 and Section 2.6.6 of Appendix C indicate that the aluminum racks do not require an AMP. Explain the discrepancy.

RESPONSE TO RAI 3.6-20:

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 row to relabel the new fuel racks is included in the response to RAI 3.6-24.

RAI 3.6-21:

Appendix C, Section 2.6.5, "Aging Management Review for Spent Fuel Pool Liner, Components, and Racks," of the LRA states that you regularly check SFP chemistry control activities under the Fuel Pool Chemistry Control Program. The staff assumes that the inspections would provide information related to corrosion, deposits, clarity of water, general cleanliness, appearance, and biological growth. 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.

RESPONSE TO RAI 3.6-21:

See the response to RAI 3.6-31.

RAI 3.6-22:

Discuss any AMP that has been successful in ensuring the proper identification, evaluation, and repair of borated water leakage with specific experience in applying the program to the SFP carbon steel bolting and other components at Hatch. Describe the scope of this program as applied to the carbon steel bolting and external valve parts in the spent fuel system and submit information about the operating experience related to the leakage of borated water from the carbon steel bolting and external valve parts of the spent fuel system.

RESPONSE TO RAI 3.6-22:

Plant Hatch is a BWR. There is no borated water used in the spent fuel pool. Demineralized water is used in the spent fuel pool.

RAI 3.6-23:

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. Clarify the environments for which the listed aging effect occurs and the AMP that manages the aging effect.

RESPONSE TO RAI 3.6-23:

Table 3.3.1-4 identifies and lists components subject to aging management review that support two intended functions. One is spent fuel storage (T24-01), and the other is for new fuel storage (T24-02). The environment for the spent fuel pool is demineralized water. The environment for the new fuel storage vault is air. Both of these structures are inside the reactor building, and hence "inside" is used for both as an environment. However, since the spent fuel pool contains demineralized water, it is the controlling environment. All structural components that list fuel pool chemistry control as an AMP are associated with the spent fuel pool.

When "inside" and "demineralized water" are noted as environments, the structural component is located such that it is exposed to both the reactor building environment and a demineralized water environment (e.g., spent fuel pool components located above or below the water line). Also see the response to RAI 3.6-24.

RAI 3.6-24:

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. Specify the applicable AMP to manage the loss of material aging effect for stainless steel components in an embedded environment or provide the basis for concluding that an AMP is not required.

RESPONSE TO RAI 3.6-24:

LRA Table 3.3.1-4 lists stainless steel "Anchors and Bolts" and "Miscellaneous Steel." Those line items in the table grouped components exposed to the fuel pool water with embedded components that are not exposed to the fuel pool water. In the table below, the two line items in Table 3.3.1-4 (Anchors and Bolts, and Miscellaneous Steel) have each been split in order to illustrate the embedded items separately.

Loss of material for embedded stainless steel components due to crevice corrosion is an aging effect requiring aging management. This aging effect is managed by the SMP, as noted in Table 3.3.1-4.

In addition, as noted in the response to RAI 3.6-20, the line item entry for aluminum storage racks has been relabeled. It is presented here with other items of Table 3.3.1-4 for convenience.

Structural Component	Component Functions	Environment	Material	Aging Effects	Aging Management Program/Activity
Anchors and Bolts / C.2.6.3	Structural Support	Inside; Embedded	Stainless Steel	Loss of Material	Structural Monitoring Program
Anchors and Bolts / C.2.6.5	Structural Support	Inside; Demin Water	Stainless Steel	Loss of Material	Fuel Pool Chemistry Control
Miscellaneous Steel / C.2.6.3	Fission Product Barrier	Inside; Embedded	Stainless Steel	Loss of Material	Structural Monitoring Program
Miscellaneous Steel / C.2.6.5	Fission Product Barrier	Demin Water; Inside	Stainless Steel	Loss of Material	Fuel Pool Chemistry Control
Storage Racks –New Fuel/ C.2.6.6	Structural Support; Nonsafety Related Structural Support	Inside	Aluminum	None	None Required

Additional information on the SMP may be found in Appendix B, Section 2.5.

RAI 3.6-25:

Bolts, which are used in safety and non-safety-related structural support, are fuel storage system components in the anchors and bolts (C.2.6.5) commodity group. Bolts are susceptible to a loss of pre-load (due to embedment, gasket creep, thermal effects, and self-loosening). Provide the basis for not including this aging effect.

RESPONSE TO RAI 3.6-25:

See the response to RAI 3.6-9.

RAI 3.6-26:

Table 3.3.1-1 of the LRA does not list any AMPs for those components exposed to an embedded environment. Embedded components (e.g., anchorage items) are susceptible to aging. Provide the basis for not providing an AMP for components exposed to an embedded environment.

RESPONSE TO RAI 3.6-26:

The structural elements of supports (struts, straps, etc.) were included with the support evaluation boundary for function L35. The support evaluation boundary did not include the components that connect the support to a structure (e.g., an embed plate or structural member). The embedded items were included under miscellaneous steel, and anchors and bolts for various functions, such as T23 (LRA Table 3.3.1-3), U29 (Table 3.3.1-8), W35 (Table 3.3.1-9), Y32 (Table 3.3.1-11), and Y39 (Table 3.3.1-12). The AMPs to manage the aging effects are the protective coatings program and the SMP.

RAI 3.6-27:

Table 3.3.1-5 of the LRA lists the Structural Monitoring Program and the Protective Coatings Program as the AMPs for panel joint seals and sealants; however, Section C.2.6.7 of the application lists Passive Component Inspection Activities, Structural Monitoring Program, and Gas Systems Component Inspections as the AMPs for this commodity group. Explain the discrepancy between the information provided in Table 3.3.1-5 and Commodity Group C.2.6.7.

RESPONSE TO RAI 3.6-27:

Commodity sections in Appendix C.2 of the Plant Hatch LRA present all of the AMPs applicable to the specific commodity under consideration. Note that <u>all</u> of the AMPs presented in each Appendix C.2 section do not necessarily apply to <u>all</u> of the components included within the commodity. The Plant Hatch LRA Section 3 tables provide this component-specific information.

Table 3.3.1-5 should not have credited the protective coatings program as an AMP for the panel joint seals and sealants. This change was provided in SNC's April 19,2000 electronic communication to the NRC. Appendix C.2.6.7 is correct in not crediting the protective coatings program as an AMP for the panel joint seals and sealants. The SMP manages the aging of the panel joint seals and sealants. The PCIA and GSCI manage aging of the flex connectors and duct gaskets in the MCRECS ductwork, which are listed in Table 3.2.4-20 (system Z41, control building HVAC).

RAI 3.6-28:

In Table 3.3.1-5 of the application for Anchors and Bolts (C.2.6.3), the staff notes that Commodity Group C.2.6.3 is established for the AMR of Seismic Category I buildings and structures and select Category II buildings and structures important to the safety of Category I structures. As intended, this AMR is not specifically focused on anchors and bolts; therefore, the applicant is requested to address the loss of pre-load as a possible aging effect for the anchors and bolts, and provide the corresponding AMPs.

RESPONSE TO RAI 3.6-28:

As noted in the RAI, LRA Section C.2.6.3 does not specifically focus on anchors and bolts, but they are included in the commodity group and are evaluated in the AMR for structural steel in buildings and structures.

See the response to RAI 3.6-9.

RAI 3.6-29:

Tables 3.3.1-1 through 3.3.1-13 of the Hatch LRA omit any reference to the various aging effects for threaded fasteners such as (1) loss of material from boric acid wastage for threaded fasteners in structural connections in the vicinity of the spent fuel pool and stress corrosion cracking, and (2) inter-granular attack of stainless steel threaded fasteners in raw water. It is not clear what AMPs are intended for the management of aging effects for threaded fasteners exposed to these environments. In addition, the above-mentioned tables do not state that self-loosening of bolted connections, due to vibration, is an aging effect requiring aging management. Furthermore, expansion and undercut anchors in concrete may loosen due to local degradation of the surrounding concrete as a result of vibratory loads. Provide the following information:

a. Identify the specific AMPs that are credited for managing each of the above noted, applicable aging effects for threaded fasteners;

b. Provide a technical justification for not identifying loss of pre-load due to the effects of vibration on concrete surrounding expansion and undercut anchors.

RESPONSE TO RAI 3.6-29:

The spent fuel pool at Plant Hatch contains no boric acid. Only demineralized water is used. Therefore, loss of material due to boric acid wastage is not possible, and an AMP is not required.

For SCC or IGA, see the response to RAI 3.6-31.

For loss of preload due to the effects of vibration on concrete surrounding expansion and undercut anchors, see the response to RAI 3.6-9.

RAI 3.6-30:

Tables 3.3.1-3 through 3.3.1-5 and Tables 3.3.1-8 through 3.3.1-13 of the Hatch LRA do not list prestressed concrete structural components. Confirm that Hatch has no prestressed concrete structural elements in its structures that are within the scope of an AMR. Otherwise, list the Hatch prestressed concrete elements requiring AMR and discuss applicable AMPs for managing their aging effects.

RESPONSE TO RAI 3.6-30:

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 el. 228 ft. 0 in. are provided to protect the refueling floor from the outside environment. The panels outside the reactor building, identified above, 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.

RAI 3.6-31:

Table 3.3.1-4, "Aging Effects Requiring Management for Components Supporting Fuel Storage Intended Functions and Their Component Functions," does not list cracking of spent fuel pool stainless steel liners as an aging effect under the structural steel category. Previous staff experience in this area has shown that stress corrosion cracking of stainless steel liners in a borated water environment is an aging effect requiring aging management. Justify your 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.

RESPONSE TO RAI 3.6-31:

Plant Hatch does not have a borated water environment in the spent fuel pool. The water in the pool is demineralized water. Operating temperature data in the spent fuel pools was reviewed, 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 Hatch 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.

RAI 3.6-32:

Loss of material is listed as an aging effect for reinforced concrete components under Tables 3.3.1-3 through 3.3.1-13 (except for Tables 3.3.1-5, 3.3.1-11 and 3.3.1-13) and cracking as an additional aging effect is added for reinforced concrete components. Section C.1.4.2, "Concrete Structural Components" of the Hatch LRA only discusses loss of material due to corrosion of embedded steel and cracking in masonry block walls due to expansion or contraction. Provide an assessment regarding the applicability of the following aging effects for Hatch reinforced concrete structural components and, as applicable, describe the AMPs that are relied on to manage these aging effects:

a. Loss of material (including scaling, spalling, pitting, and erosion) from abrasion and cavitation, aggressive chemicals.

b. Cracking from elevated temperature, fatigue, freeze-thaw, reaction with aggregates, shrinkage, or settlement.

c. Cracking of equipment pad from vibratory motion or fatigue.

d. Change in material properties from aggressive chemical attack, elevated temperature (e.g., sustained exposure to temperature greater than 150 °F) irradiation embrittlement, or leaching of calcium hydroxide.

RESPONSE TO RAI 3.6-32:

As stated in the Introduction to Section C.1, only relevant aging effects are discussed in the LRA - that is, those aging effects requiring management in the period of extended operation. The AMR for structures determined that the following aging effects are not applicable to Plant Hatch:

a. Loss of material from abrasion, cavitation and aggressive chemicals:

   The structures are not subjected to flowing fluids with velocities that could cause abrasion or cavitation, and operating experience confirms the absence of these degradation effects. As described in FSAR Table 2.4-10, the groundwater and river water were chemically tested to confirm that they are not aggressive (pH > 5.5, < 500ppm chloride and < 1500ppm sulfates), and internal structures are not exposed to aggressive chemicals on a sustained basis.

b. Cracking from elevated temperature, fatigue, freeze-thaw, reaction with aggregates, shrinkage and settlement:

   The NRC's draft SRP-LR addresses elevated temperature for concrete in section 3.5.2.2.1.3 (and in many other sections). It states that the GALL report recommends further evaluation if any portion of the concrete containment components exceeds specified temperature limits, (i.e., general temperature > 150 °F and local temperature > 200 °F). General elevated air temperatures in the Plant Hatch concrete structures do not exceed 150 °F on a sustained basis, except for the sacrificial shield wall area surrounding the reactor vessel. Local air temperatures are less than 200 °F except for the upper elevations of the sacrificial shield wall. The principal function of the sacrificial shield wall concrete is shielding, which is not affected by elevated temperature.

   For a discussion of elevated temperature, refer to the RAI 3.6-32 response.

   Expansion, shrinkage, and cracking due to chemical reactions between certain aggregates and alkalis are not a concern for concrete components at Plant Hatch because non-reactive aggregates were used during construction. Testing of the aggregate per ASTM C-289 during construction minimized or precluded the use of reactive aggregates (see Unit 2 FSAR, Section 3.8.4.6.1.C and FSAR Tables 3.8-17 and 3.8-18).

Shrinkage of concrete occurs early in life during the curing process, and is not an age related degradation mechanism. It has not been observed at Plant Hatch subsequent to construction.

Total and differential settlement of these structures is monitored at Plant Hatch. The settlement curves (Unit 2 FSAR – Figures 2A-17, and 2A-18) flattened out in 1978 and have remained flat, indicating that no subsequent measurable settlement has occurred. Inspections of the concrete structures have not identified any cracking associated with settlement.

c. Cracking of equipment pad from vibratory motion or fatigue:

See the response to RAI 3.6-9.

d. Change in material properties from aggressive chemical attack, elevated temperature, irradiation embrittlement, or leaching of calcium hydroxide:

Aggressive chemical attack and elevated temperature are not applicable to Plant Hatch, as discussed above in item b. Irradiation embrittlement is not an applicable aging mechanism for Plant Hatch concrete structures since the maximum projected radiation exposure of 4.5×10^{16} neutrons/cm^2 for 60 years will be far below the established threshold value of 5×10^{19} neutrons/cm^2.

Concrete used in the Plant Hatch structures was constructed in accordance with the guidance provided in ACI 318-63, and plant construction specifications. Increases in porosity and permeability due to the leaching of calcium hydroxide are not a concern for concrete components designed and constructed in accordance with the ACI standards.

RAI 3.6-33:

Tables 3.3.1-3 through 3.3.1-10, 3.3.1-12 and 3.3.1-13 list loss of material as the only aging effect for Hatch's structural steel components. Section C.1.4.1, "Structural Steel and Aluminum Components," only provides an aging effect assessment that covers loss of material and cracking. Please provide an assessment of the applicability of the following aging effects for Hatch's structural steel components and, as applicable, describe the AMPs that are relied upon to manage these aging effects:

a. Cracking of SFP liner, spent fuel rack and structural steel in the SFP.

b. Loss of material, cracking and loss of pre-tension of anchorages/embedments.

c. Loss of material of battery racks, checkered plates, expansion anchors, specialty doors, instrument line supports, instrument racks and frames and grating supports.

d. Loss of structural steel supports by corrosion exposure to boric acid wastage.

RESPONSE TO RAI 3.6-33:

a. The Plant Hatch fuel pool contains demineralized water at an operating temperature < 140 °F. No known cracking mechanism is active at these environmental conditions for the stainless steel components in the fuel pool. Cracking of the stainless steel fuel pool structures and components was determined, therefore, to not be an aging effect requiring management.

b. Loss of material for anchors and embedments is addressed in the LRA in Appendix C.2.6.1 and C.2.6.3. For loss of preload and cracking of concrete, see the response to RAI 3.6-9.

c. Battery racks, checkered plates, expansion anchors, specialty doors, instrument line supports, instrument racks and frames and grating supports are included in the category of "Miscellaneous steel , safety and non-safety related" in various tables throughout the LRA. Loss of material was evaluated as an aging effect requiring management for these components. Two AMPs have been credited for the management of loss of material, the SMP and the protective coating program, as shown in Tables 3.3.1-1 to 3.3.1-13.

d. Plant Hatch is a BWR and does not use boric acid. Boric acid wastage was determined not to be applicable.

RAI 3.6-34:

Does Hatch have any earthen embankments as part of its ultimate heat sink system or intake structure? As applicable, discuss the aging effects of these structures due to (a) loss of material from erosion and (b) cracking due to settlement.

RESPONSE TO RAI 3.6-34:

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.

RAI 3.6-35:

Tables 3.3.1-1 through 3.3.1-13 of the LRA do not list fire barrier penetration seals as components requiring AMR. The staff views these fire barrier penetration seals as within scope and subject to an AMR. Describe how the aging effects for fire barrier penetration seals is evaluated and discuss the AMP used to adequately manage the effect.

RESPONSE TO RAI 3.6-35:

Fire barrier penetration seals are addressed in LRA Table 3.2.4-18. Aging effects requiring management are discussed in LRA Section C.2.3.4.1.

RAI 3.6-36:

In Sections 2.4.3 and 2.4.6 of the LRA, the drywell electrical and mechanical components are scoped as requiring AMRs. Table 7.3-1 of the Unit 1 Updated Final Safety Analysis Report (UFSAR, Rev. 17R) indicates that there are a number of penetrations (in addition to the vent line penetrations) penetrating the suppression chamber. Please provide information regarding the aging effects considered for these penetrations in both Hatch units.

RESPONSE TO RAI 3.6-36:

See LRA Tables 3.3.1-3, 3.3.1-6 and 3.4.1-1. Primary containment penetrations penetrate the drywell shell plate and the torus shell plate. The aging effect considered for these penetrations is loss of material. The AMR for these penetrations, both mechanical and electrical, is presented in Appendix C, Section C.2.6.2. One TLAA is also applicable to containment penetrations. For details of that TLAA, see LRA Section 4.5.

RAI 3.6-37:

Table 3.3.1-3 describes the intended function of all containment penetrations as a "fission product barrier." However, the main functions of these penetrations vary (i.e., personnel or equipment access, carrying steam lines or feedwater lines or electrical cables). Depending upon the function that containment penetrations perform and their location, the local environment (i.e. temperature, humidity, borated water, torus water, radiation) and loads will differ in and around these penetrations. The aging effect "loss of material" or loss of leak tightness (deterioration of the penetration seals and gaskets) will be dependent on these different environments. Please discuss these aging effects with respect to the various groups of containment penetrations subjected to similar environments.

RESPONSE TO RAI 3.6-37:

The entire concept of how aging management is presented in the Plant Hatch LRA is based on the premise stated in the RAI. LRA Appendix C.2 presents commodity groups that were established based on materials and environments. Aging effects requiring management are directly related to component materials and environments. In some cases, AMPs for component members of a commodity group may be dependent on component function. These cases are addressed as needed in the AMRs. Specific AMPs for a component are identified in the applicable Section 3 table.

Thus, containment penetrations were evaluated for each environment to which they are exposed. The LRA presents the results of the evaluations by discussing the set of aging effects requiring management. For components supporting the intended function of containment integrity, see the various C.2 sections noted in Table 3.3.1-3 and 3.3.1-6.

RAI 3.6-38:

Table 7.3-1 of the Unit 1 UFSAR and the description of the penetrations in Section 5.2 of the Unit 1 UFSAR indicate that there are several penetrations with bellows in addition to the bellows inside the vent pipes. Provide a discussion of the environment and aging effect considerations for these bellows including the effects of pressure and thermal movement.

RESPONSE TO RAI 3.6-38:

See the response to RAI 3.6-37.

RAI 3.6-39:

Table 3.3.1-7 of the LRA states that the reactor building (RB) penetration function is a "fission product barrier." Hatch Unit 1 UFSAR Section 5.3.3.2 states that "penetrations of the secondary containment system are designed to have leakage characteristics consistent with secondary containment leakage requirements." If the SMP (Section A.2.5 of the LRA) is applicable to these penetrations, it is not quite clear how the leak-tightness function of the penetrations is being managed by this program. Since the leak-tightness of a number of mechanical, electrical, and access penetrations depends upon the aging effects on seals and gaskets, explain why loss of leak-tightness should not be included in the column of "Aging Effects," in Table 3.3.1-7 of the LRA. Also, provide information as to how the leak-tight integrity of the penetrations is managed under the existing AMPs and will be managed during the period of extended operation.

RESPONSE TO RAI 3.6-39:

This RAI addresses reactor building, or secondary containment, penetration seals. Secondary containment is not designed to be leak-tight. Rather, it has controlled leakage characteristics, and is maintained at a negative air pressure relative to the outside, so that air flow is into the building. These characteristics are confirmed periodically by secondary containment leakage tests. However, 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.

RAI 3.6-40:

The Protective Coatings Program (A.2.3 of the LRA) is stated as one of the two AMPs for monitoring the aging effects of RB penetrations. The enhancements section (A.2.3.5 of the LRA), which would be effective during the period of extended operation, will include the inside, outside, submerged, and buried environment for the RB penetrations. Please provide information regarding how you plan to benchmark the RB penetration protective coatings program as part of the enhanced program.

RESPONSE TO RAI 3.6-40:

See Appendix B, Section 2.3, for a discussion of the protective coatings program.

A baseline inspection program will be done for the penetrations. The periodicity of future inspections will be determined by a plant coating specialist based on the findings of the initial inspection.

RAI 3.6-41:

The ISI program description in Section A.1.9 indicates that you are using or planning to use the 1992 Edition and 1992 Addenda of Subsection IWE of Section XI of the ASME Code for inspection of the containment and its penetrations. Information Notice (IN) 88-82, "Torus Shells with Corrosion and Degraded Coatings in BWR Containments," and further staff evaluation has determined that pitting corrosion occurs due to accumulation of debris and stagnant water near certain torus penetrations. For both the units at Hatch, provide a description of your current augmented inspection program (Ref. IWE-1240) for such suspect sites, including your findings in the previous inspections, and the measures you have taken to ensure the integrity of such suspect sites against potential corrosion (i.e. loss of material) for the period of extended operation.

RESPONSE TO RAI 3.6-41:

The submerged surfaces of the Unit 1 and Unit 2 tori have been determined to not require augmented ISI at Plant Hatch.

Unit 1 Suppression Pool Interior Submerged Surfaces

During the spring 1990 refueling outage, visual examination of submerged surfaces of the torus was performed by divers. An extensive desludging, visual examination, and patch coating repair program was begun in 1991. Results of this activity showed that the submerged surfaces were experiencing some coatings degradation, and that some shell pitting had occurred, but that shell thicknesses were acceptable. Visual inspections, desludging, and patch coating repairs have been performed in each refueling outage since 1991. A long-range suppression pool maintenance program is in place at Plant Hatch. This long-range plan for the torus shell and supports is implemented by the protective coatings program.

Ultrasonic examinations of corroded and pitted areas in the submerged areas have shown that the actual shell thicknesses are well above the required minimum shell thickness. This area was recoated in 1981, there has been no significant degradation of the submerged area, and the degradation rate is very slow.

Plant Hatch plans to continue desludging, visual examination, and spot coating repairs periodically, based on the history of past inspections.

Unit 2 Suppression Pool Interior Submerged Surfaces

During the spring 1991 refueling outage, an extensive desludging, visual examination, and patch coating repair program were begun. Results of this activity showed that the submerged surfaces were in good condition. Examinations were performed again in the 1995 refueling outage and visual inspections, desludging, and patch coating repairs have been performed in each outage since 1995. A long-range suppression pool maintenance program is in place at Plant Hatch. This long-range plan for the torus shell and supports is implemented by the protective coatings program.

Ultrasonic examinations of corroded and pitted areas in the submerged areas have shown that the actual shell thicknesses are well above the required minimum shell thickness. This area was recoated in 1981, and there has been no significant degradation of the submerged area and the degradation rate is very slow.

Plant Hatch plans to continue desludging, visual examination, and spot coating repairs periodically, based on the history of past inspections.

RAI 3.6-42:

IN 92-20, "Inadequate Local Leak Rate Testing," and further staff evaluations have determined that the local leak rate testing or the general visual examination of the accessible parts of two-ply bellows does not lend itself to the detection of corrosion of the bellows. Subsection IWE does not provide any requirement or acceptance criteria, except that the bellows could be examined under augmented inspection. Describe the operating experiences related to the performance of these bellows at the two units of Hatch, the methods used to detect the potential corrosion of the bellows (including that of vent line bellows), and any corrective actions that were taken.

RESPONSE TO RAI 3.6-42:

Plant Hatch utilizes bellows assemblies similar to those described in IN 92-20. Following receipt of IN 92-20, Georgia Power Company decided to select a sample of three

bellows for augmented testing at the next outage to evaluate the adequacy of the LLRT methods and procedures. A plate was welded inside containment to test the bellows in the proper direction. The tests confirmed that the LLRT testing methods and procedures were acceptable. Visual inspections, performed prior to testing, provide assurance that the bellows are in an acceptable condition for testing.
Some of the two-ply bellows assemblies on Unit 2 have been replaced because of bellows leakage detected during LLRT. The bellows leakage was caused by the inadvertent exposure of the bellows to chlorides during maintenance activities.

RAI 3.6-43:

The RB penetrations carrying the high energy piping are subjected to an environment more challenging than the other RB penetrations. Also, the access penetrations through the reactor building walls are subjected to a number of cycles of openings and closings. Provide information regarding the operating experience related to these penetrations and the AMP developed to address the pertinent degradation issues.

RESPONSE TO RAI 3.6-43:

The NRC's draft SRP-LR addresses elevated temperature for concrete in section 3.5.2.2.1.3 (and in many other sections). It states that the GALL report recommends further evaluation if any portion of the concrete containment components exceeds specified temperature limits, i.e., general temperature greater than 150 °F, and local temperature greater than 200 °F. General elevated air temperatures near the Plant Hatch concrete structures do not exceed 150 °F on a sustained basis, except for the sacrificial shield wall surrounding the reactor vessel. Local air temperatures are less than 200 °F, except for the upper elevations of the sacrificial shield wall.

The purpose of the secondary containment access doors is to provide access for personnel and equipment. The secondary containment provides, in conjunction with the primary containment and other engineering safeguards, the capability to limit releases to the environment. The intended function of those doors is to maintain secondary containment integrity. The doors and their frames are made of steel. The door frames are anchored into concrete or concrete masonry walls with expansion or wedge anchors, and are not exposed to water and high humidity. Doors and frames are typically coated with a rust inhibitor primer and a finish coat of paint. Aging effects for structural steel doors and frames are loss of material. The SMP and protective coatings program are credited for aging management of these components.

RAI 3.6-44:

Assuming, as indicated in Table 3.3.1-7 of the LRA, that the SMP (summarized in Section A.2.5 of the LRA) is, and will be, used for the aging management of the RB penetrations, provide information regarding the extent of use of NEI 96-03,"Industry Guideline for Monitoring the Condition of Structures at Nuclear Power Plants," Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," and

ACI 349.3R-1996, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," in managing the aging of components of electrical, mechanical, and access penetrations (i.e. the base metal, water seals, seals and gaskets, and welds) together with the information regarding the acceptance criteria used as indication of significant aging effects.
RESPONSE TO RAI 3.6-44:

NEI 96-03 and ACI349.3R-1994 were consulted in the development of the SMP. The penetrations in question (re: Table 3.3.1-7) are secondary containment penetrations, and therefore Regulatory Guide 1.163, "Performance-Based Containment Leak Test Program" is not applicable.
Acceptance criteria for the SMP may be found in Appendix B Section 2.5.

RAI 3.6-45:

Subsection IWE of Section XI of the ASME Code in conjunction with 10 CFR 50.55a, "Codes and Standards," requires the general visual (VT-1) examination of the containment penetrations 3 times in 10 years. For concrete structures, in general, ACI 349.3R-96 recommends the minimum inspection frequencies of twice in a 10-year interval. The RB penetrations are required to be essentially leak-tight. Provide information regarding the justification for using the baseline inspection interval of 5 operating cycles (7 to 10 years) for the RB penetrations as indicated in Section A.2.5 of the LRA.

RESPONSE TO RAI 3.6-45:

IWE applies to primary containment, not to the reactor building penetrations. The IWE visual inspection is used to detect degradation of the pressure-retaining portion of the primary containment. This visual inspection may be used to determine aging effects. The ACI code is applicable for the evaluation of concrete structures only, and the inspection frequency referenced above has no applicability for metal penetrations. The leak-tightness of the penetrations is maintained by a secondary containment test outlined in Technical Specification SR 3.6.4.1.

The SMP periodic inspection frequency for the reactor building was initially set at five years and adjusted after the baseline inspections. For Plant Hatch, the baseline inspection was conducted in 1998, and the next inspection is due in 2003. Thereafter, it will be conducted every five cycles. The SMP has criteria and guidance for adjusting inspection intervals based on inspection results. The five-cycle interval has been established based on the results of baseline verification. See Appendix B, Section 2.5, for additional discussion of the SMP inspections.

RAI 3.6-46:

Clarify whether the Torque Activities AMP is applicable to anchors and bolts used in the (1) intake structure, (2) yard structures, (3) main stack, (4) EDG building, and (5) control building.

RESPONSE TO RAI 3.6-46:

The torque activities AMP is not applicable to structural anchors and bolts used in the subject buildings and structures. See Appendix B, Section 1.11, for a description of the anchors and bolts addressed by the torque activities AMP.

RAI 3.6-47:

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 RB, control building, and main stack. Discuss in detail how the licensee intends to manage the aging effects of these masonry walls and describe how the licensee's 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 Licensee Actions in Response to IE Bulletin 80-11."

RESPONSE TO RAI 3.6-47:

NRC I&E 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 I&E 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, Plant Hatch established and 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 large enough 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 Plant Hatch had appropriately complied with 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 I&E Bulletin 80-11.

However, masonry block wall cracks may be caused by age-related degradation mechanisms. During one walkdown pursuant to the SMP, cracking was observed in concrete masonry block walls. The observed cracks were considered minor and insignificant, and were noted for comparison in future walkdowns.

The SMP monitors the condition of the structures and other civil components.

RAI 3.6-48:

Table C.1.1-1, "Plant Hatch Thermal and Radiation Environments" shows expected or measured temperatures at key plant locations. With respect to the Primary Containment at Hatch, the table does not provide maximum temperatures within key containment locations. Please provide maximum recorded or observed temperatures within the Hatch 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. 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).

RESPONSE TO RAI 3.6-48:

Operating temperature data in the spent fuel pools was reviewed, and the maximum recorded pool temperature did not exceed 115 °F.

The maximum observed average temperatures in the main steam cubicle for Unit 1 during a nearly twelve year period was 126 °F, and for Unit 2 during a 5 year period was 154 °F.

In the region of the reactor vessel supports, the maximum observed temperature for Unit 1 during a 7 year period was 112 °F, and for Unit 2 during a nearly 11 year period was 140 °F.

The maximum air temperature recorded at the sacrificial shield wall (Unit 2) during the approximately 10-1/2 year period was 210 °F (observed 12 % of time). This temperature was recorded at elevation 180'-0", Azimuth 90°, near the surface of the concrete wall. The average temperature over the same period was 184 °F. This temperature was used to evaluate the thermal effect on the containment wall where it was found that the temperature would be less than 150 °F at 2.5" inside the concrete.

The NRC's draft SRP-LR addresses elevated temperature for concrete in section 3.5.2.2.1.3 (and in many other sections). It states that the GALL report recommends further evaluation if any portion of the concrete containment components exceeds specified temperature limits, i.e., general temperature greater than 150 °F, and local temperature greater than 200 °F. General elevated air temperatures near the Plant Hatch concrete structures do not exceed 150 °F on a sustained basis, except for the sacrificial shield wall surrounding the reactor vessel. Local air temperatures are less than 200 °F, except for the upper elevations of the sacrificial shield wall.

The SMP inspection process assesses the condition of the in-scope structures, and identifies any ongoing degradation. SMP will inspect the exposed and accessible concrete for loss of material, cracking and spalling.

RAI 3.6-49:

Tables 3.3.1-3 through 3.3.1-5 and 3.3.1-8 through 3.3.1-13 of the Hatch LRA do not list cracking of equipment support concrete pads as an applicable aging effect requiring AMR. Staff experience with other LRAs indicates the frequent occurrence of such cracks around anchor bolt regions. Discuss the AMP for managing this aging effect or justify your exclusion of this aging effect from the tables listed above.

RESPONSE TO RAI 3.6-49:

Equipment support foundations, pads and the 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" was identified as the aging mechanism (see Section C.1.4.2 and Section C.2.6.1). The SMP has been credited as the AMP. The applicable 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.

In addition, see the response to RAI 3.6-9.

RAI 3.6-50:

Based on previous staff experience, degradation of piping systems (e.g., loss of integrity of bolted closures, cracking of welds and loosening of bolts) may potentially be caused by vibration (mechanical or hydrodynamic) loading. In Table 3.3.1-3, the applicant did not identify loss of preload as an aging effect for bolting in the primary containment system. 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. If these vibration-related aging effects were excluded, provide the basis.

RESPONSE TO RAI 3.6-50:

Table 3.3.1-3 identifies the aging effects that require aging management for in-scope components that support the T23-01 intended function. There are two categories of bolts that apply to the primary containment system: bolts used in the containment structure itself; and those used in the bolted connections of pipe that serve as part of the primary containment boundary. As described in SNC's electronic communication of June 20, 2000, loss of preload in bolted connections of pipe was inadvertently omitted from Table 3.3.1-3. However, loss of preload is only an aging effect requiring management for the bolts used in piping connections. The AMR for these bolts is discussed in LRA Appendix C, Section C.2.2.10-1.

Vibration, as an aging mechanism leading to loss of preload, manifests itself early in the operation of a bolted closure after the bolts are torqued. The amount of preload prescribed for a bolted connection includes a vibration component. The torque activities AMP determines the amount of preload for the bolted connections.

Similarly, other vibration related component failure modes (e.g., cracking of pipe weldments) occur as a result of inadequate original design, inadequate vibration testing at start-up or after a design change, a change in the operating characteristic of the components, or an unanticipated operational event. None of these causes are age-related, and an inspection program would not be beneficial in reducing vibration related component failures.

As described in Section 3.9 of the Unit 2 FSAR, the Plant Hatch design is in conformance with the ASME Code with regards to the treatment of vibration in component design.

RAI 3.6-51:

The scoping requirements of 10 CFR 54.4(a)(2) include all non safety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs 10 CFR 54.4 (a)(1)(i), (ii), or (iii). In Section 2.1.2.5 of the LRA, the applicant stated that the few cases where non safety-related components could impact safety-related functions were included in the scope of license renewal in accordance with the criteria of 10 CFR54.4(a)(2). Table 3.3.1-3 includes 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. Provide clarification on this and on how the aging management programs for the non safety-related piping segments and components have been addressed. Specifically, state whether the same aging management programs discussed in LRA Table 3.3.1-3 also apply to "Seismic II over I" piping components.

RESPONSE TO RAI 3.6-51:

LRA Table 3.3.1-3 addresses components supporting the primary containment integrity function, including safety related and nonsafety-related components inside containment. However, component supports for piping are included in Table 3.3.1-1, Piping Specialties (L35). Table 3.3.1-1 includes Seismic Category I and Seismic Category II/I components inside containment as described in the table.

The AMPs credited in Table 3.3.1-3 for piping include Seismic Category II/I piping as described in Sections C.2.2.2.2, C.2.2.3.1, C.2.6.2, C.2.2.9.1 and C.2.2.9.2. However, only nonsafety-related piping that is in scope is included. Nonsafety-related piping not in scope is not included. The AMPs credited in Table 3.3.1-1 for piping specialties also include Seismic Category II/I components and component supports as described in Section C.2.6.4. Also, see the response to RAI 3.4-11.

RAI 3.6-52:

In Table 3.3.1-8, for reinforced concrete components, cracking is not included as an aging effect. Cracking is an aging effect for reinforced concrete. Section C.2.6.1

excludes cracking as an aging effect for turbine building masonry block walls. Provide the basis for not identifying cracking of masonry block walls as an applicable aging effect for block walls within the turbine building.

RESPONSE TO RAI 3.6-52:

The masonry block walls at Plant Hatch were evaluated per requirements of NRC I&E Bulletin 80-11. 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. An in-house calculation reviewed all the masonry block walls, and only those in the reactor building, control building, and the main stack met the requirements of the NRC Bulletin 80-11. The results of this evaluation are presented in Unit 2 FSAR Table 3.8-20.

RAI 3.6-53:

In Section C.2.6.1 of the LRA, underground duct runs and pull boxes are identified as concrete components requiring aging management review. However, these components are not listed under specific items and areas inspected to establish a base line condition as part of the SMP. Discuss the aging effects that are applicable to these components and, as applicable, describe the AMPs that can be relied upon to manage the identified aging effects.

RESPONSE TO RAI 3.6-53:

The underground duct runs and pull boxes are concrete components associated with the yard structures intended function of equipment integrity and personnel habitability. These underground duct runs and pull boxes are listed in LRA Section 2.4.10, and the components identified and listed in Table 2.4.10-1 as reinforced concrete.
Table 3.3.1-10 identifies loss of material as an aging effect requiring management and notes that the structural monitoring program and protective coatings program will manage this aging effect. The AMR for this component is addressed in Appendix C.2.6.1.

RAI 3.6-54:

Table 3.3.1-8 does not address aging management of the overhead crane, including crane rails and girders. Identify and discuss the aging effects that are applicable to these components and, as applicable, describe the AMP that can be relied upon to manage the identified aging effects.

RESPONSE TO RAI 3.6-54:

The overhead crane in the turbine building is not in scope for license renewal. Refer to LRA Table 2.2-1.

RAI 3.6-55:

Provide a discussion of your operating experience with the turbine pedestal. Industry experience has indicated occurrence of cracks in turbine pedestals as an aging effect. Discuss your basis for not addressing this aging effect in an AMP for the turbine pedestal.

RESPONSE TO RAI 3.6-55:

Per the discussion in RAI 2.4-TB-1, only certain portions of the turbine building are in scope. These portions do not include the turbine pedestal, and hence, cracks in the pedestal are not evaluated. However, the HPCI and RCIC turbine pads are in-scope and covered by the SMP.

TIME-LIMITED AGING ANALYSES

RAI 4.1-1:

Table 4.1.1-1 of the LRA lists the TLAAs applicable to Plant Hatch. Flaw growth analysis was not identified as a TLAA. Flaws in Class 1 components that exceed the size of allowable flaws defined in IWB-3500 of the ASME Code need not be repaired if they are analytically evaluated to the criteria in IWB-3600 of the ASME Code. The analytic evaluation requires the licensee to project the amount of flaw growth due to fatigue and stress corrosion cracking mechanisms, or both, where applicable, during a specified evaluation period. Identify all Class 1 components that have flaws exceeding the allowable flaw limits defined in IWB-3500 and that have been analytically evaluated to IWB-3600 of the ASME Code. Provide the results of the analyses that indicate whether the flaws will satisfy the criteria in IWB-3600 for the period of extended operation.

RESPONSE TO RAI 4.1-1:

SNC reviewed the ISI flaw growth evaluations for Plant Hatch and found none that met the definition of a TLAA as defined by the criteria of 10 CFR Part 54.3. Flaw growth evaluations for Plant Hatch were not made for a forty-year period. Most evaluations were made for a forty-month period.

RAI 4.1-2:

Table 4.1.1-1 identifies piping stress analyses that consider thermal fatigue cycles as a TLAA. The table does not identify the fatigue analyses of other reactor coolant pressure boundary components or the reactor vessel internals as TLAAs. Section 4.2 of the LRA does address the reactor pressure vessel. Identify whether any other components of the reactor coolant pressure boundary have fatigue analyses. In addition, Section C.3.2.2 of the Hatch Unit 1 FSAR indicates that a fatigue analysis of the reactor vessel internals was performed. Describe the TLAAs performed to address fatigue for reactor coolant pressure boundary components, except for the reactor vessel, that were not included in Table 4.1.1-1 and describe the TLAA performed for the reactor vessel internals. Indicate how these TLAAs meet the requirements of 10 CFR 54.21(c).

RESPONSE TO RAI 4.1-2:

SNC reviewed the fatigue analyses for the reactor vessel, its components, and the rest of the primary coolant boundary, and applied the criteria of BWRVIP-74 for determining whether they are significant enough to be a TLAA. Those analyses that met the definition of a TLAA (pursuant to 10 CFR Part 54.3) are included in Chapter 4 of the LRA. The rest of the analyses did not meet the definition of a TLAA.

RAI 4.2-1:

Section 4.2.2 of the LRA contains a discussion of the Plant Hatch licensing basis pipe break criteria. Part of the Plant Hatch pipe break criteria involves postulation of pipe breaks at locations where the calculated fatigue usage exceeds a specified value. The usage factor calculation used to identify postulated pipe break locations meets the definition of a TLAA as specified in 10 CFR 54.3. Provide a description of a TLAA for the pipe break criteria at Plant Hatch. Describe how the TLAA meets the requirements of 10 CFR 54.21(c).

RESPONSE TO RAI 4.2-1:

SNC employs a design process that meets its current license basis commitment to Branch Technical Position MEB 3-1. After an evaluation of this criterion and discussions with the NRC in 1999, SNC views these analyses to be a selection criterion that establishes a bounding set of locations for line break consideration. Therefore, the results of the analyses at 40 years need not be reestablished for 60 years. When a design, whether a totally new ASME Code Class 1 design or a change to an existing Class 1 design, results in an analysis that predicts a piping CUF of greater than 0.1 for the extended license term, SNC will consider the location for a pipe break in accordance with the BTP. There is no TLAA associated with this design process.

RAI 4.2-2:

Section 4.2.2 of the LRA contains a discussion of Generic Safety Issue (GSI) 190, "Fatigue Evaluation of Metal Components For 60-year Plant Life." GSI-190 addresses the effect of the reactor water environment on the fatigue life of metal components. The discussion in Section 4.2.2 indicates that EPRI license renewal fatigue studies have demonstrated that sufficient conservatism exists in the design transient definitions to compensate for potential reactor water environmental effects. The staff does not agree with the contention that the EPRI fatigue studies have demonstrated that sufficient conservatism exists in the design transient definitions to compensate for potential reactor water environmental effects. The staff identified several technical concerns regarding the EPRI studies. The staff technical concerns are contained in an August 6, 1999, letter to NEI. Although these concerns involved the EPRI procedure and its application to PWRs, the technical concerns regarding the application of the Argonne National Laboratory (ANL) statistical correlations and strain threshold values are also relevant to BWRs. In addition to the concerns referenced above, the staff has additional concerns regarding the applicability of the EPRI BWR studies to Plant Hatch. EPRI Report TR-107943, "Environmental Fatigue Evaluations of Representative BWR Components," addressed a BWR-6 plant and EPRI Report TR-110356, "Evaluation of Environmental Thermal Fatigue Effects on Selected Components in a Boiling Water Reactor Plant," used plant transient data from a newer vintage BWR-4 plant. The applicability of the EPRI fatigue studies to Plant Hatch has not been demonstrated. Provide the following additional information regarding resolution of the environmental fatigue issue:

a. Indicate whether the staff comments provided in the staff's August 6, 1999, letter to NEI, which are applicable to Hatch, have been considered in the assessment of the environmental fatigue issue at Plant Hatch. Discuss how the applicable staff comments were considered in the evaluation of environmental fatigue.

b. Discuss the applicability of the component fatigue assessments in the EPRI Reports TR-107943 and TR-110356 to components in Hatch Units 1 & 2. The discussion should include a comparison of design transients, operating cycles and fabrication details for each component. Also include a comparison of the hydrogen water chemistry used at Hatch with the hydrogen water chemistry considered in the EPRI reports.

c. The staff assessed the impact of reactor water environment on fatigue life at high fatigue usage locations and presented the results in NUREG/CR-6260, "Application of NUREG/CR-5999, 'Interim Fatigue Curves to Selected Nuclear Power Plant Components'," March 1995. Formulas currently acceptable to the staff for calculating the environmental correction factors for carbon and low-alloy steels are contained in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and those for austenitic stainless steels are contained in NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design of Austenitic Stainless Steels." Provide an assessment of the 6 locations identified in NUREG/CR-6260 for an older vintage BWR-4 considering the applicable environmental fatigue correlations provided in NUREG/CR-6583 and NUREG/CR-5704 reports for Hatch Units 1 and 2.

RESPONSE TO RAI 4.2-2:

a. The staff comments provided in the August 6, 1999, NRC letter to NEI have been considered in the assessment of the environmental fatigue issue at Plant Hatch through the margins present by considering design basis severity of thermal transients.

Primarily, the NRC concerns presented in the August 6, 1999 letter are associated with the more recent laboratory fatigue data in simulated LWR reactor water environments that have been generated by ANL since the time of the EPRI generic studies. These data have resulted in improved environmental correction factor correlations, which are documented in NUREG/CR-6583 (for carbon/low alloy steel) and NUREG/CR-5704 (for stainless steel). The improved correlations were not available at the time the EPRI generic studies were performed.

For carbon and low-alloy steels, the correlations published in NUREG/CR-6583 do not differ substantially from the correlations used in the EPRI generic studies. However, the change in strain threshold may have a significant effect, and that effect has been evaluated, as follows.

A recalculation was performed based on one of the examples contained in EPRI Report No. TR-105759, "An Environmental Factor Approach to Account for Reactor Water Effects in Light Water Reactor Pressure Vessel and Piping Fatigue Evaluations," December 1995, for a BWR carbon steel feedwater piping location with a design-basis fatigue usage factor of 0.1409 for 40 years. An alternating stress threshold of 30 ksi (approximating the alternating strain threshold of 0.10%) was used initially to adjust the incremental fatigue usage for eight out of thirty-one load pairs, giving an additional (environmental) fatigue usage of 0.0477, for a 40-year adjusted total of 0.1886. The overall environmental multiplier (F_{en}) in this case was 1.34 (1.68 for the eight affected load pairs).

Reducing the alternating stress threshold to 21 ksi (approximating the revised alternating strain threshold of 0.07%) would require an environmental adjustment for six additional load pairs. Assuming that the F_{en} multiplier of 1.68 would continue to apply for the fourteen affected load pairs, the estimate for the adjusted fatigue usage factor would be

$$0.1409 - 0.0803 + 1.68\ (0.0803) = 0.1955.$$

The overall F_{en} multiplier increases only to 1.39.

Because the additional load pairs that would have to be included contribute relatively small increments to the total CUF, the change in the strain range threshold does not cause a significant impact on the calculated fatigue usage. Therefore, the results of the EPRI generic studies provide a reasonable estimate of the impact of potential environmental fatigue effects for carbon/low alloy steel components, and are considered to remain valid.

For austenitic stainless steels, the data are more penalizing than the data used in the EPRI generic studies.

For the case of relatively low temperature (< 200°C), a low (bounding) strain rate, and either high or low dissolved oxygen, the environmental shift is 2.55. For relatively high temperature (> 200°C), low dissolved oxygen, and a low (bounding) strain rate, the environmental shift may be as high as 15.35, although there is a reduction above 250°C where the environmental factor decreases to about 3.20 at 340°C. These factors are higher than those obtained from the relationships used in the EPRI generic studies. As a result, further evaluation was performed as described below.

For most of the component locations evaluated in the EPRI generic studies, these most recent data do not pose a problem for the demonstration that the 60-year CUF is less than 1.0, including reactor water environmental effects. Again, a significant benefit accrues to the F_{en} approach in this regard, since most of the penalizing thermal transients in the BWR environment lie below the threshold temperature of 200°C. Therefore, the environmental shift is relatively low, provided that separate multipliers are used for the portions of the transient that are above and below 200°C. However, for the most fatigue-sensitive PWR locations, (e.g., surge line elbows), the environmentally-adjusted CUF increases over that calculated in the EPRI generic studies by a factor of about two. Therefore, a reasonable approach to accounting for the more recent laboratory data for stainless steel material is to conservatively apply a factor of 2.0 to the EPRI generic study results. This is considered to be very conservative for the BWR.

The CUF results from the most applicable EPRI generic study (EPRI TR-110356, see Item (b) below) are shown in Table 1, with modifications to account for the more recent data in NUREG/CR-6583 and NUREG/CR-5704. The design basis fatigue usage for each location is also shown for comparison. The results in Table 1 clearly demonstrate that the conservatism of design basis transient definitions overwhelms all environmental effects. The CUF for all locations, including environmental effects and projected to 60 years, is at least a factor of 12.9 below the original design basis CUF.

These results indicate that tracking CUF based on design basis transient definitions, such as the Plant Hatch CCTLP does, provides conservative estimates of CUF for the license renewal period.

b. The most applicable evaluation for Plant Hatch with respect to the EPRI generic studies is EPRI Report No. TR-110356, "Evaluation of Environmental Thermal Fatigue Effects on Selected Components in a Boiling Water Reactor." The other two EPRI reports (EPRI Report Nos. TR-107515 and TR-107943) have limited direct applicability to Plant Hatch, but were referenced in the Plant Hatch application for completeness, since the EPRI studies built off the results of each other. It was therefore considered necessary to reference the main EPRI study (EPRI Report No. TR-107515), along with both follow-on studies performed for BWRs, to provide a comprehensive reference source.

Nevertheless, focusing on EPRI Report No. TR-110356, those results are considered directly applicable to Plant Hatch. First, the results documented in that report apply to a BWR-4 that is identical to the Plant Hatch design. Therefore, the Class 1 systems associated with the plants are the same, which defines the characteristics of the thermal transients in these systems. As a result, the design basis transient definitions associated with the plants are very similar. This is demonstrated in Table 2, where the design basis transient definitions for both plants are compared.

The BWR-4 evaluated in EPRI Report No. TR-110356 did not consider hydrogen water chemistry (HWC), as evidenced by the plots of dissolved oxygen in that report. Both units at Plant Hatch have implemented HWC. The maximum effect of the change in dissolved oxygen as a result of HWC implementation is adequately addressed via the conservative factors described under the response to Item (a) above.

There are only two issues relevant to fabrication details and the associated effects of reactor water environment on fatigue. First, the sulfur content, where applicable, was conservatively assumed to be at a maximum level in EPRI TR-110356. Second, the material type (i.e., stainless or carbon/low alloy steel) is similar between the two plants, and was considered appropriately in all fatigue evaluations. In fact, material types between most BWRs are very similar, as evidenced by the comparison shown in Table 3 between Plant Hatch and the older vintage BWR-4 evaluated in NUREG/CR-6260. Therefore, fabrication details are not considered to have any effect on the application of the results in EPRI Report No. TR-110356 to Plant Hatch.

c. The locations investigated in NUREG/CR-6260 for the older vintage BWR are listed in Table 3. Also shown in Table 3 are the equivalent locations where CUF is monitored via the Plant Hatch CCTLP, and the projected 60-year CUF for each location based on plant operation to-date.

Table 3 demonstrates that all BWR locations from NUREG/CR-6260 were evaluated for Plant Hatch. All of these locations are either bounded by locations monitored via the Plant Hatch CCTLP or the design 40-year CUF is below the 0.10 threshold for monitoring by the program. The projected CUFs for all monitored locations remain within the allowable value of 1.0 for the license renewal period. Furthermore, the Plant Hatch CCTLP includes several other locations (nine total, five on Unit 1 and four on Unit 2), beyond those evaluated in NUREG/CR-6260, thereby providing a more comprehensive CUF assessment. Note that the Plant Hatch RHR suction piping that Table 3 credits for monitoring two of the NUREG/CR-6260 locations is being removed from the CCTLP because a newer stress analysis shows the 40-year CUF for that location below the 0.10 threshold for monitoring.

As discussed in the response to Item (a) above, the appropriate correlations from NUREG/CR-6583 and NUREG/CR-5704 have been accounted for via the conservatism in design basis transient definitions.

TABLE 1
Revised Fatigue Usage Results for BWR (Including Environmental Effects)

Case No.	Location	Projected 60 Year Usage Factor from TR-110356 (with F_{en})	Correction Factor to Account for NUREG/CR-6583 or NUREG/CR-5704	Revised 60 Year Usage Factor (with F_{en}) (1)	Design Basis Fatigue Usage (2)	Margin (3)
1	1 = CRD Penetration	0.034	2.0	0.068	0.875	12.9
	2 = FW Loop A Safe End	0.009	2.0	0.018	0.471	26.2
	3 = FW Loop A Nozzle Forging	0.001	1.0	0.001	< 0.1	~100
	4 = FW Loop B Safe End	0.009	2.0	0.018	0.471	26.2
	5 = FW Loop B Nozzle Forging	0.001	1.0	0.001	< 0.1	~100
2	1 = CRD Penetration	0.013	2.0	0.026	0.875	33.7
	2 = FW Loop A Safe End	0.009	2.0	0.018	0.471	26.2
	3 = FW Loop A Nozzle Forging	0.001	1.0	0.001	< 0.1	~100
	4 = FW Loop B Safe End	0.009	2.0	0.018	0.471	26.2
	5 = FW Loop B Nozzle Forging	0.001	1.0	0.001	< 0.1	~100
3	1 = CRD Penetration	0.016	2.0	0.032	0.875	27.3
	2 = FW Loop A Safe End	0.009	2.0	0.018	0.471	26.2
	3 = FW Loop A Nozzle Forging	0.001	1.0	0.001	< 0.1	~100
	4 = FW Loop B Safe End	0.009	2.0	0.018	0.471	26.2
	5 = FW Loop B Nozzle Forging	0.001	1.0	0.001	< 0.1	~100

Notes: 1. The "Revised 60-Year Usage Factor" is equal to the "Projected 60-Year Usage Factor from TR-110356" multiplied by the "Correction Factor to Account for NUREG/CR-6583 or NUREG/CR-5704."

2. As documented in the governing design basis fatigue analysis report.

3. The "Margin" is equal to the "Design Basis Fatigue Usage" divided by the "Revised 60-Year Usage Factor."

TABLE 2
Design Basis Plant Transient Comparison for the BWR-4 in EPRI Report No. TR-110356 vs. Plant Hatch

Transient	BWR-4 No. of Cycles	Hatch Unit 1 No. of Cycles	Hatch Unit 2 No. of Cycles
Boltup	123	123	123
Design Hydrostatic Test	130	130	130
Startup	117	120	117
Turbine Roll & Increase to Rated Power	not specified	120	not specified
Daily Reduction to 75% Power	10,000	10,000	10,000
Weekly Reduction to 50% Power	2,000	2,000	2,000
Rod Pattern Change (Rod Worth Test)	400	400	400
Loss of Feedwater Heaters, Turbine Trip with 100% Steam Bypass, Unit 1 = Turbine Trip at 25% Power	10	10	10
Loss of Feedwater Heaters, Partial Feedwater Heater Bypass	70	70	70
SCRAM, Turbine Generator Trip, Feedwater On, Isolation Valves Stay Open	40	40	40
SCRAM, All Other	140	147	140
Rated Power Normal Operation	not specified	not specified	not specified
Reduction to 0% Power	111	118	111
Hot Standby	111	118	111
Shutdown/Vessel Flooding	111	118	111
Unbolt	123	123	123
Refueling	not specified	not specified	not specified
Pre-Operational Blowdown	10	0	10
Loss of Feedwater Pumps, Isolation Valves Close	5	10	5
Reactor Over Pressure with Delayed SCRAM, Feedwater Stays On, Isolation Valves Stay Open	1	1	1
Single Relief or Safety Valve Blowdown	8	2	8
Automatic Blowdown	1	0	1
Improper Start of Cold Recirculation Loop	1	5	1
Sudden Start of Pump in Cold Recirculation Loop	1	5	1
Improper Startup with Recirculation Pumps Off & Drain Shut Off	1	0	1
Pipe Rupture and Blowdown	1	0	not specified
Natural Circulation Startup	3	0	3
Loss of AC Power, Natural Circulation Restart	5	0	5
Code Hydrostatic Test	0	3	3

TABLE 3
Locations Evaluated in NUREG/CR-6260 for Older Vintage General Electric Plant (BWR-4) vs. Plant Hatch

NUREG/CR-6260 Location	NUREG/CR-6260 Material	Addressed by Plant Hatch CCTLP?	Plant Hatch Material	Projected 60-Year CUF for Plant Hatch (1)
Reactor Vessel (Lower Head to Shell Transition)	SA-302 Low Alloy Steel	YES (2)	SA-533 Grade B Class 1 Low Alloy Steel	U1 = 0.0669 U2 = 0.0513
Feedwater Nozzle (Bore)	SA-508 Low Alloy Steel	YES	SA-508 Class 2 Low Alloy Steel	U1 = 0.1663 U2 = 0.3643
Recirculation System (RHR Return Line Tee)	SA-358 Type 304 Stainless Steel	YES (3)	SA-358 Type 316NG Class 1 Stainless Steel	U1 < 0.1500 (7) U2 < 0.1500(7)
Core Spray System (Nozzle)	SA-302 Grade B Low Alloy Steel	YES (4)	SA-508 Class 2 Low Alloy Steel	U1 = 0.4796 U2 = 0.2983
Core Spray System (Safe End)	SA-376 Type 316 Stainless Steel	YES (5)	SA-182 Type F304 Stainless Steel	U1 = 0.1605 U2 < 0.1500(7)
Residual Heat Removal Line (Tapered Transition)	SA-358 Type 304 Stainless Steel	YES (3)	SA-358 Type 316NG Class 1 Stainless Steel	U1 < 0.1500 (7) U2 < 0.1500(7)
Feedwater Line (RCIC Tee)	SA-106 Grade B Carbon Steel	YES (6)	SA-106 Grade B Carbon Steel	U1 = 0.5607 U2 = 0.7435(8)

Notes:
1. Based on actual transient counts through 12/31/1999.
2. The limiting location in the RPV shell is monitored for both units at Plant Hatch, which is considered to adequately represent the NUREG/CR-6260 location.
3. The limiting location in the Unit 2 RHR suction piping, at the elbow near the recirculation suction tee, was monitored in the Plant Hatch CCTLP, and was considered to adequately represent the NUREG/CR-6260 location. Newer stress analysis shows the 40-year CUF < 0.10, so this location will no longer be monitored. The 40-year design CUF < 0.10 for the Unit 1 RHR suction piping and was never monitored by the CCTLP. Therefore, the CCTLP addresses this location for both units by determining the CUF is below the threshold for monitoring.
4. The RPV recirculation inlet nozzle, which bounds the core spray nozzle at Plant Hatch, is monitored for both units in the Plant Hatch CCTLP. This is considered to adequately represent the NUREG/CR-6260 location.
5. The limiting location in the Unit 1 core spray piping system is monitored in the Plant Hatch CCTLP, and is considered to adequately represent the NUREG/CR-6260 location. The 40-year design CUF < 0.10 for the Unit 2 core spray piping system.
6. The limiting location in the feedwater piping system is monitored for both units in the Plant Hatch CCTLP, which is considered to adequately represent the NUREG/CR-6260 location. On Unit 1, the monitored piping includes the HPCI, RCIC, and RWCU Class 1 piping connected to the feedwater line.
7. The 40-year design CUF is less than 0.10 for this location so it is not monitored.
8. The RCIC Tee on Unit 2 is in the Class 2 portion of the system. The CUF given is for the bounding location on the Class 1 portion of the feedwater line.

RAI 4.2-3:

Section 4.2.3 of the LRA discusses the TLAA for non-Class 1 piping. The application indicates that the current design basis for some piping and tubing is 14,000 cycles. Identify the piping and tubing that were designed for 14,000 cycles and provide the basis for this specified number of cycles. Indicate how the projected operating cycles were determined to be less than 14,000 for 60 years in the TLAA evaluation.

RESPONSE TO RAI 4.2-3:

The two TLAAs that assume 14,000 thermal cycles are design guides (one for each unit of Plant Hatch) created for standardizing tube routing and supports. The tubing and supports for which the designers used these design guides are in many systems and support many in-scope system functions. The design guide follows the designer's rule-of-thumb that instrumentation tubing should be designed for twice as many thermal cycles as the process piping to which the tubing is connected. An assumption of 14,000 thermal cycles implies a thermal cycle every one and one-half days over a 60-year operational life. Thus, this assumption is very conservative, and therefore meets criterion (ii) of 10CFR Part 54.21(c)(1).

RAI 4.2-4:

Section A.1.12.1 of the LRA describes the Component Cyclic or Transient Limit Program. The application indicates that the program "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." Provide a summary of the Component Cyclic of Transient Limit Program that addresses the elements listed below. The summary should also include a discussion of the bases for each of the elements.

a. Scope of the program that includes the specific structures and components subject to fatigue monitoring, including the location monitored for each structure or component. Provide the current CUF for each location monitored and describe the method used to estimate the current CUF and the method used to estimate the CUF at 60 years;

b. Preventive actions that will be used to mitigate or prevent fatigue degradation;

c. Parameter(s) to be monitored and the monitoring device(s) at each location monitored by the program;

d. Assurance that detection of fatigue degradation will occur before loss of the structure or component intended functions;

e. Program monitoring, trending, inspection technique, testing frequency, and sample size to ensure maintenance of structure and component intended functions;

f. The method used to compare the monitored data to the fatigue analysis of record;

g. Acceptance criteria to ensure structures and components perform their intended functions; and

h. Operating experience from similar programs or inspection techniques used by Southern Nuclear Operating Company or the industry.

RESPONSE TO RAI 4.2-4:

The Component Cyclic or Transient Limit Program is described in detail in Appendix B, Section 1.12. Also, see the responses to RAIs 3.1.12.1, 3.1.12-3, and 3.1.12-5. The following table provides the current and projected CUFs for Class 1 piping and the torus.

Table
Class 1 Piping and Torus CUFs

Class 1 Monitored Location	Current CUF	60-Yr CUF
U1 RPV Equalizer Piping	0.1276	0.5287
U1 Core Spray Piping	0.0689	0.1605
U1 SLC Piping	0.0239	0.2316
U1 FW in Rx Bldg.	0.4301	0.5607
U1 Main Steam, HPCI & RCIC	0.0532	0.0665
U2 FW RPV to Main Iso Valve	0.4062	0.7435
U2 Pri Stm Condensate Drain	0.5106	0.9189
U2 Main Steam, HPCI & RCIC	0.0092	0.0169
U1 Torus	0.3500	0.6756
U2 Torus	0.2191	0.7391

RAI 4.4-1:

Section 4.4.5 of the LRA lists various commodity types based on option (i) of 10 CFR Part 54.21 (c)(1) to demonstrate that the analyses remain valid for the period of extended operation. For each commodity type that is based on option (i), provide a summary of the thermal and radiation analyses used to illustrate the basis upon which the qualified life remains valid for the period of extended operation.

RESPONSE TO RAI 4.4-1:

For convenience, SNC has grouped the requested summary of the analyses with the figure from the application. It should be noted that this RAI addresses only those analyses that are based on option 54.21 (c)(1)(i). Some qualification packages have components that are evaluated using more than one option. Thus, the summary figure in the application may show that options (i), (ii), and/or (iii) were used for that package while the corresponding summary presented here will show only option (i).

Many of the Figures in the LRA which provide EQ evaluation summaries state that qualified life limitations due to cycle aging will be reevaluated before extending qualified lives beyond the current operating license term. The evaluations of cycle aging for EQ equipment are now complete, and the results have been incorporated into the qualified life calculations and replacement intervals of the affected equipment. No option 1 evaluations were changed as a result of cycle aging reevaluation.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-12

Commodity Type: Molded Case Circuit Breaker (MCCB)

Specific Description: Westinghouse HFB (Thermal Magnetic & Magnetic), HFD, HMCP

Location: Outside Containment

QDP: Unit 1/2, QDP 6G/6G

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit (i): Valid for the Period of Extended Operation

The Westinghouse HFB (Thermal Magnetic & Magnetic), HFD, and HMCP Molded Case Circuit Breakers (MCCBs) are qualified for use in MCCs on El.130' of the Reactor Building (Unit 1) and El.130' & 185' of the Reactor Building (Unit 2). Only de-energized applications are qualified for the period of extended operation and included in this summary.

Thermal

A 90°F ambient is assumed for both units for ease of qualification demonstration. This considers design and actual temperatures, and is conservative for both units (Ref. 1, 4). In addition, 18°F heat rise inside the MCCs is assumed from the test report. The resulting normal service temperature used to determine qualified life is 108°F.

An activation energy of .87 eV was used. The following summarizes aging performed and the resulting qualified lives:

HFB – 51 days @ 240°F – 56.3 years
HFD – 80 days @ 240°F – 88.4 years
HMCP – 50 days @ 240°F – 55.2 years

The HFD's are qualified through the end of the period of extended operation. The HFB's and HMCP's are qualified through the end of the period of extended operation when installed after year 4 and 5, respectively.

Radiation

The worst-case 60-year total integrated dose for the MCCs is 6.65 E5 Rads (Ref. 2). The components received a test dose of 2.8 E6 Rads.

Equipment Qualification (EQ) Summary

Application Figure 4.4-13

Commodity Type: Thermal Overload Relays with Heaters

Specific Description: Westinghouse Type AA & AN Relay w/ FH Series Heater Element

Location: Outside Containment

QDP: Unit 1/2, QDP 6H/6H

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit (i): Valid for the Period of Extended Operation

The Westinghouse Type AA & AN Thermal Overload Relays with FH Series Heater Elements are qualified for use in MCCs on El.130' of the Reactor Building (Unit 1) and El.130' & 185' of the Reactor Building (Unit 2). Only de-energized applications are qualified for the period of extended operation and included in this summary.

Thermal

An 85°F ambient is used for both units for qualification, based on actual temperatures (Ref. 4). This is conservative for both units. In addition, 18°F heat rise inside the MCCs is assumed from the test report. The resulting normal service temperature used to determine qualified life is 103°F. The heater elements are metallic and not sensitive to thermal aging. The qualified life is established for the relay.

An activation energy of .96 eV was used. The following summarizes aging performed and the resulting qualified life:

43 days at 240°F - 114 years.

Radiation

The worst-case 60-year total integrated dose for the MCCs is 6.65 E5 Rads (Ref. 2). The components received a test dose of 2.8 E6 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-22

Commodity Type: Solenoid Valve

Specific Description: Target Rock Corporation Model 76HH-002

Location: Outside Containment

QDP: Unit 1/2, QDP 10/8

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit (i): Valid for the Period of Extended Operation

The type test performed on Target Rock model 76HH-002 is used to qualify models used at Plant Hatch. This summary addresses Target Rocks qualified for use outside containment in areas excluding the steam chase and personnel access areas.

Thermal

Ambient temperatures of 120°F for Unit 1 and 110°F for Unit 2 are used for qualification, and are conservative for both units (Ref. 1, 4).

An activation energy of .86 eV was used, and is the limiting activation energy for the component materials per the vendor test report. The following summarizes aging performed and the resulting qualified life:

33 days @ 350°F – 601 years for Unit 1 de-energized applications

33 days @ 350°F - 1038 years for Unit 2 de-energized applications

Radiation

The worst-case 60-year total integrated dose for outside containment is 1.40 E7 Rads (Ref. 2). The components received a test dose of 3.53 E7 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-23

Commodity Type: Solenoid Valve Upgraded with Modification Kits

Specific Description: Target Rock Corporation Model 82X-007H

Location: Outside Containment

QDP: Unit 1/2, QDP 10A/8A

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit (i): Valid for the Period of Extended Operation

The qualification test was performed on Target Rock model 82X-007H. The solenoid valves at Plant Hatch upgraded with the modification kits are qualified by similarity. This summary includes various outside containment applications, excluding the steam chase and personnel access rooms.

Thermal

The de-energized solenoid valves are qualified as long as subcomponent (coils, seals, and electronics) replacement intervals are adhered to. Worst-case design ambient temperatures (120°F for Unit 1 and 105°F for Unit 2) were used for qualification, and are conservative for both units (Ref.1,4).

For normally energized solenoid valves in Unit 1, a worst-case temperature of 100°F is assumed based on actual temperatures (Ref. 4) to extend the qualified life/replacement intervals of solenoid valve electronics to 10 years. This temperature is also conservative.

Activation energies of .98, 1.14, and 1.04 eV were used for the rectifier, switch, and terminal board, respectively from the vendor test report.

Aging was for 46 days @ 280°F

Qualified Life:

De-energized applications - 60 years with elastomer seal replacement at 10 year intervals and other subcomponent replacements at 20 year intervals.

Energized applications (Unit 1 only) - 60 years with solenoid coil replacement at 20 year intervals and all other subcomponent replacements at 10 year intervals.

Radiation

The worst-case 60-year total integrated dose for outside containment is 1.40 E7 Rads (Ref. 2). The components received a test dose of 2.71 E8 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-24

Commodity Type: Solenoid Operated Globe Valve

Specific Description: Target Rock Corporation Model 91J-001

Location: Outside Containment

QDP: Unit 1, QDP 10B

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

The qualification test was performed on Target Rock model 82X-007H. Model 91J-001 is qualified by similarity. This summary includes normally de-energized applications outside containment in Unit 1, excluding the steam chase and personnel access room.

Thermal

The solenoid valves are qualified as long as subcomponent (coils, seals, and electronics) replacement intervals are adhered to. Worst-case design ambient temperature (120°F) was used for qualification, and is conservative (Ref.1,4)

From the vendor test report, aging was for 46 days @ 280°F and qualifies the electrical components and elastomer seals for 20 years plus 2 years margin at a base temperature of 160°F, per the vendor.

Radiation

The worst-case 60-year total integrated dose for outside containment applications is 2.51 E6 Rads (Ref. 2). The components received a test dose of 2.71 E8 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-25

Commodity Type: Fan Motor

Specific Description: Reliance Class H Type RH Insulation System

Location: Outside Containment

QDP: Unit 2, QDP 9

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

This summary applies only to two Unit 2 motors installed in 1996. These Reliance Class H Type RH Insulation System fan motors are qualified for use in the Unit 2 SE Diagonal.

Thermal

The design ambient temperature is 104°F in the SE Diagonal and is conservative (Ref.1,4).

Aging was for 88 days @ 491°F. The original qualified life was calculated to be 44 years by the vendor, and assumed 122°F (50°C) ambient + 105°C heat rise and hot-spot. 44 years is sufficient to qualify the motors through the end of the period of extended operation considering installation dates. *

*Note: A subsequent thermal evaluation has been performed to extend the thermal qualified life to 60 years, which assumed a higher ambient and more realistic duty cycles. However, mechanical aging limits the qualified life to the original 44 years.

The vendor report did not state the activation energy, but it could be determined from the aging data to be 1.015 eV.

Radiation

The worst-case 60-year total integrated dose for the SE Diagonal is 6.15 E6 Rads (Ref. 2). The components received a test dose of 2.2 E8 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-34

Commodity Type: Solenoid Valve

Specific Description: ASCO NP and 206 Series

Location: Outside Containment

QDP: Unit 1/2, QDP 22/20

Methodology: NUREG 0588

TLAA Disposition Option: Crit. (i): Valid for the Period of Extended Operation

This summary includes only de-energized ASCO models NP8344 and NP8320, and ASCO 206 Series Solenoid Valves located outside containment in areas excluding the steam chase and personnel access room.

Thermal

The worst-case design ambient for both units (120°F) is assumed, and is conservative for both units (Ref. 1, 4).

An activation energy of 0.94 eV was used. The following summarizes aging performed and the resulting qualified lives:

NP8320 – 12 days @ 143°C – 69 years
NP8344 – 12 days @ 145°C – 78 years
206 Series – 12 days @ 151°C – 113 years

Radiation

The ASCO NP and 206 Series solenoid valves with EPDM elastomers were tested to 2.0 E8 Rads. The worst-case 60-year total integrated dose inside/outside containment is 1.22 E8 Rads (Ref.2).

The Viton elastomers were tested to 2.0 E7 Rads. The worst-case 60-year total integrated dose for applications using Viton elastomers is 1.40 E7 Rads for the Unit 1 Torus (Ref.2).

Equipment Qualification (EQ) Summary

Application Figure: 4.4-35

Commodity Type: Limit Switches

Specific Description: NAMCO EA180 and EA740

Location: Outside Containment

QDP: Unit1/2, QDP 23/15

Methodology: NUREG 0588, 10 CFR 50.49

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended

The NAMCO EA180 and EA740 limit switches included in this summary are located outside containment in areas excluding the steam chase and personnel access room.

Thermal

A worst-case design ambient of 120°F is assumed for all Unit 1 and 2 applications included in this summary, and is deemed conservative (Ref.1,4).

An activation energy of 0.8 eV was used. The following summarizes aging performed and the resulting qualified life:

3,618 hours @ 248°F – 76.5 years

Radiation

The worst-case 60-year total integrated dose outside-containment for applications included in this summary is 1.40 E7 Rads (Ref.2). The components received a test dose of 5.0 E7 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-36

Commodity Type: Pressure Switch

Specific Description: Pressure Controls, Inc. (PCI) Model PPD 147D8668P003

Location: Inside Containment

QDP: Unit 1/2, QDP 25/25

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

Component qualified lives in the drywell have been evaluated using actual service temperature data. (Ref.3)

Thermal

Thermal aging was for 146 hours at 126.6° C. The activation energy is 1.57 (from the vendor's Arrhenius analysis). The Pressure Controls pressure switches are qualified for more than 60 years at temperatures at or below 136° F (Ref.3).

Radiation

The 60-year total integrated dose inside containment is 1.22 E8 Rads (Ref. 2). The components received a test dose of 2.2 E8 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-39

Commodity Type: Radiation Detector

Specific Description: Victoreen Model 877-1 Detector

Location: Inside Containment

QDP: Unit 1/2, QDP 28/30

Methodology: NUREG 0588 Cat.1

TLAA Disposition Option: Detector: Crit.(i): Valid for the Period of Extended Operation

This summary includes only the radiation detector, and not the cable.

Thermal

No thermal aging was required for the detector, as all parts are stainless steel, nickel, or aluminum. The radiation detector is not age-sensitive, and is qualified for 60 years. The detector is refurbished, re-calibrated and re-certified every 5 years.

Radiation

The 60-year total integrated dose inside containment is 1.22 E8 Rads (Ref. 2). The components received a test dose of 2.2 E8 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-40

Commodity Type: Solenoid Operated Globe Valves

Specific Description: Target Rock 82VV Series

Location: Outside Containment

QDP: Unit 2, QDP 31

Methodology: NUREG 0588, Cat. I

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

This summary includes only de-energized Unit 2 applications located in the HPCI room and Reactor Building El. 130'.

Thermal

Aging was performed for 33 days at 345°F minimum. Per the manufacturer, an activation energy of .61 eV was used. The qualified life was calculated to be 62 years at 110°F. The design ambients for HPCI and R.B. El are 105°F and 90°F, respectively, and are deemed conservative (Ref.1,4).

Radiation

The worst-case 60-year total integrated dose is 2.37 E6 Rads for R.B. El. 130' (Ref. 2). The components received a test dose of 1.35 E8 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-43

Commodity Type: Pressure Switch

Specific Description: Static-O-Ring Model 4N6-B5-NX-C1A -JJTTX6

Location: Outside Containment

QDP: Unit 1/2, QDP 32/65

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

The pressure switches are located in the N.E Diagonal (Unit 2); and the N.E. and S.E. Diagonals, and Reactor Building El. 130' (unit 1).

Thermal

Aging was performed for 100 hours at 302°F and an additional 177.7 hours at 250°F. Per the vendor test report, an activation energy of 1.18 eV was used. The qualified life was calculated to be 345 years at 120°F. This exceeds the maximum design ambient of 104°F for these applications, which is also deemed conservative (Ref.1,4).

Radiation

The worst-case 60-year total integrated dose is 6.15 E6 Rads for the Diagonals (Ref. 2). The components received a test dose of 3.3 E7 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-44

Commodity Type: Pressure Switch

Specific Description: Static-O-Ring Model 4N6-B5-U8-C1A -JJTTNQ

Location: Outside Containment

QDP: Unit 1/2, QDP 32A/65A

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

The Static-O-Ring Model 4N6-B5-U8-C1A -JJTTNQ pressure switch qualification covers applications in the Northeast and Southeast Diagonals only.

Thermal

Aging was for 422 hours at 230 °F. The activation energy, taken from the vendor report, was 1.05 eV. Using design ambient temperatures of 100 and 104°F for Unit 1 and 2 respectively (Ref.1) plus heat rise, qualified life is calculated to be 58.8 years for Unit 1 and 44.7 years for Unit 2. Though this is less than 60 years for both units, based on installation dates, all applications are qualified through the end of the period of extended operation.

Radiation

The worst-case 60-year total integrated dose for the Diagonals is 6.15 E6 Rads (Ref. 2). The components received a test dose of 3.3 E7 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-47

Commodity Type: Temperature Elements and RTV Sealant

Specific Description: Weed Model 1AOD/611-1B-C-4-C-2-A2-0

Location: Inside Containment

QDP: Unit 1/2, QDP 35/37

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

For components inside containment qualified lives have been evaluated using actual service temperature measurements yielding a range of qualified lives depending on the application-specific temperature (Ref.3).

Thermal

Aging was performed for 724 hours at 304°F. The activation energy was 0.8 eV (per the vendor test report). Qualified lives were calculated using actual temperature data recorded for each temperature element (Ref.3). Applications with average equivalent temperatures below 127°F are qualified for more than 60 years.

Radiation

The 60-year total integrated dose inside containment is 1.22 E8 Rads (Ref. 2). The components received a test dose of 3.03 E8 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-51

Commodity Type: Heat Trace System for Post-LOCA H2 & O2 Analyzers

Specific Description: Thermon Model SSK, Heater Cable Pipe Assembly (HCPA)

Location: Outside Containment

QDP: Unit 2, QDP 41

Methodology: 10 CFR 50.49

TLAA Disposition Option: Unit 2: Crit.(i): Valid for the Period of Extended Operation

The Heat Trace System Control Panels are exempt from environmental qualification requirements due to location in a mild environment.

For Unit 2, the Heater Cable Pipe Assembly (HCPA) qualification is valid for the period of extended operation.

Thermal

Aging was for 128 hours at 257°F. The activation energy is 1.13 eV (per the vendor test report). The qualified life was calculated using the worst-case Unit 2 design ambient temperature (outside containment) of 105°F for the Torus room. This temperature is deemed conservative (Ref. 1,4).

Qualified life is calculated to be 98 years.

Radiation

The worst-case 60-year total integrated dose outside containment for the HCPA is 1.40 E7 Rads (Ref. 2) for the Torus room. The components received a test dose of 2.27 E8 Rads.

Equipment Qualification (EQ) Summary

Application Figure:	4.4-65
Commodity Type:	Space Heater
Specific Description:	Ward Leonard 30/25F Limit Switch Compartment Space Heater
Location:	Outside Containment
QDP:	Unit 1/2 QDP 59/63
Methodology:	DOR Guidelines
TLAA Disposition Option:	Crit.(i): Valid for the Period of Extended Operation

The Ward Leonard 30/25F Limit Switch Compartment Space Heaters are installed in the Limit Switch compartments of Limitorque MOV operators. Qualification is by analysis.

Thermal

These heaters are wire wound or carbon film resistive elements encapsulated in a vitreous enamel or ceramic glaze. The materials of construction are not considered age sensitive for the time and temperatures at Hatch. Limitorque has stated these heaters are not required for environmental qualification of the limitorque actuators nor are they required for normal valve operation. The purpose of the heaters is to control moisture during storage or operation.

Radiation

The materials of construction for the heaters are not considered sensitive to the radiation levels at Hatch. The radiation threshold for the wire-wound and carbon composition resistors is 1.0 E9 Rads, compared to a worst-case 60-year total integrated dose of 1.22 E8 Rads for all inside and outside-containment applications.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-69

Commodity Type: Temperature Switches

Specific Description: Fenwal Thermoswitches (Model 18021-0)

Location: Outside Containment

QDP: Unit1 QDP 66

Methodology: DOR Guidelines

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

The Fenwal Thermoswitch (Model 18021-0) is qualified by test and analysis.

Thermal

Aging was performed for 28 days at 120°C. The weak link activation energy of 1.14 eV (for the nylon braid) was used. The qualified life calculation was performed using a normal ambient temperature of 105°F, and exceeds the design ambient temperature of 100°F, which is conservative (Ref.1,4). The qualified life was calculated to be 386 years.

Radiation

The worst-case 60-year total integrated dose is 4.0 E7 Rads (Ref. 2). Qualification is by similarity to a switch tested to 2.0 E8 Rads.

Equipment Qualification (EQ) Summary

Application Figure:	4.4-72
Commodity Type:	Pilot Light
Specific Description:	General Electric CR104L Pilot Light
Location:	Outside Containment
QDP:	Unit 1QDP 67D
Methodology:	DOR Guidelines
TLAA Disposition Option:	Crit.(i): Valid for the Period of Extended Operation

The General Electric CR104L Pilot Light assemblies in the Standby Gas Treatment System are qualified by similarity analysis.

Thermal

Aging was for 817 hours @ 235°F. An activation energy of 0.96 eV was used (per the vendor test report).

An ambient temperature of 105°F was used for the SGTS room in the qualified life calculation, which is conservative (Ref.1). Qualified life was calculated to be 70.91 years.

Radiation

The test dose was 4.47 E7 Rads minimum, for the light and switch. The specified 60-year total integrated dose is 4.0 E7 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-75

Commodity Type: Heater Elements

Specific Description: Chromalox Heater Elements Models 50-47499 & 33-47499

Location: Outside Containment

QDP: Unit1/2 QDP 68/75

Methodology: DOR Guidelines

TLAA Disposition Option: Crit. (i): Valid for the Period of Extended Operation

The Chromalox Heater Elements (Models 50-47499 & 33-47499) are qualified by type test and analysis.

Thermal

Aging was for 28 days @ 120°C. An activation energy of 1.25 eV was used (per the vendor test report). An ambient temperature of 105° was assumed and is conservative (Ref.1).

Qualified life was calculated to be 883 years.

Radiation

The test dose was 2.0 E8 Rads versus a specified 60-year total integrated dose of 1.0 E7 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-78

Commodity Type: Splice Tape

Specific Description: United Controls International Model UCI-003XS

Location: Inside/Outside Containment

QDP: Unit 1/2, QDP 80/80

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit. (i): Valid for the Period of Extended Operation

The United Controls International Model UCI-003XS Splice Tape was recently qualified for new applications at Plant Hatch.

Thermal

Aging was for 381 hours @ 302°F. Per the vendor test report, an activation energy of 2.0 eV was used.

Assuming a maximum service temperature of 90°C (194°F) for cable applications, qualified life is calculated to be 375 years.

Radiation

The test dose was 1.18 E8 Rads versus 1.22 E8 Rads worst-case 60-year total integrated dose inside containment. However, the worst-case 42-year total integrated dose (including margin on the accident) is 1.0 E8 Rads. 42 years represents the maximum installed life through the end of the period of extended operation.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-84

Commodity Type: Pressure Switch

Specific Description: ITT Barton Model 580A-2 Differential Pressure Switch

Location: Outside Containment

QDP: Unit 2, QDP 34

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

The ITT Barton Model 580A-2 Differential Pressure Switch is used in the Reactor Building on elevation 158'.

Thermal

Aging was for 275 hours at 125°C. The weak-link activation energy is 0.87 eV, and is from the vendor test report.

A 90°F design temperature is used (Ref.1) resulting in a calculated qualified life of 70.2 years.

Radiation

Test dose was 5.5 E7 Rads minimum, versus a specified 60-year total integrated dose of 2.51 E6 Rads (Ref.2).

Equipment Qualification (EQ) Summary

Application Figure: 4.4-86

Commodity Type: Form Wound Motor

Specific Description: Reliance Electric Model FNA-6856 & -6857

Location: Outside Containment

QDP: Unit 2, QDP 45A

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

The Reliance Electric Model FNA-6856 & -6857 Form Wound Motors are qualified to the requirements of 10 CFR 50.49 as replacements for original DOR equipment.

This summary was written to address the TLAA demonstration, which noted that any replacement motors installed in the future would be qualified through the end of the period of extended operation based on the original qualification.

There were no motors installed that met the Criterion (i) disposition option.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-88

Commodity Type: Temperature Element

Specific Description: Rosemount 88-51-90 & 88-13-6

Location: Outside Containment

QDP: Unit 2, QDP 50

Methodology: DOR Guidelines

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

The Rosemount 88-51-90 & 88-13-6 Temperature Elements have been replaced as part of the DOR upgrade program. There are no longer any installed.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-89

Commodity Type: Fan Motor

Specific Description: Farr Co. / Westinghouse Life-line 284T Frame Motor

Location: Outside Containment

QDP: Unit 2 QDP 71

Methodology: DOR Guidelines

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

The Farr Co. / Westinghouse Life-line 284T frame motors are used in the Standby Gas Treatment System Filter Train Room.

Thermal

Aging was for 7533 hours at 210°C. An activation energy of 1.0 eV was used for the motor insulation system.

A 90°F ambient was assumed, and is conservative (Ref.1). In addition, internal heat rise of 72°C + 10°C hot-spot for the motor windings were added to arrive at a maximum service temperature of 114.2°C.

This yielded a qualified life of 320.5 years.

Radiation

Test dose was 1.13 E8 Rads minimum for the stator windings, and 2.0 E8 Rads for the motorettes and grease.

The specified 60-year total integrated dose is 3.2 E6 Rads.

Equipment Qualification (EQ) Summary

Application Figure:	4.4-90
Commodity Type:	Control Transformer
Specific Description:	Allen Bradley 1497-N20 Control Transformer (and attached X-277745 Fuse Block)
Location:	Outside Containment
QDP:	Unit 2 QDP 72A
Methodology:	DOR Guidelines
TLAA Disposition Option:	Crit.(i): Valid for the Period of Extended Operation

The Allen Bradley 1497-N20 Control Transformer (and attached X-277745 Fuse Block) is used in the Standby Gas Treatment System.

Thermal

Aging was for 672 hours @ 120°C. The weak-link activation energy is 0.98 eV (per the vendor report).

The design ambient of 90°F was assumed and is conservative (Ref.1). A temperature rise of 18°F was added, for a resulting service temperature of 108°F.

Qualified life is 99.3 years.

Radiation

The specified 60-year total integrated dose is 1.5 E6 Rads. The test dose was 2.0 E8 Rads.

Equipment Qualification (EQ) Summary

Application Figure:	4.4-92
Commodity Type:	Motor Starters
Specific Description:	Westinghouse A200 M2CAC Motor Starter and Interlocks
Location:	Outside Containment
QDP:	Unit 2 QDP 72C
Methodology:	DOR Guidelines
TLAA Disposition Option:	Crit.(i): Valid for the Period of Extended Operation

The Westinghouse A200 M2CAC Motor Starter and Interlocks are used in the Standby Gas Treatment System Control Panels. The starter is qualified by type test, and the interlocks are qualified by analysis.

Thermal

Aging was 71 days @ 115°C for the starter, with an activation energy of 0.87 eV (per the vendor report). The interlock had a 1.0 – 1.67 eV range for glass polyester.

A service temperature of 108°F was established by adding 18°F heat rise in the panel to the 90°F design ambient which is deemed conservative (Ref.1).

Qualified life was calculated to be 79.26 years for the starter, and at least that for the interlock.

Radiation

The 60-year total integrated dose is 1.5 E6 Rads (Ref.2). The test dose was 2.0 E6 Rads for the starter, and 7.9 E7 Rads by material analysis for the interlock.

Equipment Qualification (EQ) Summary

Application Figure:	4.4-93
Commodity Type:	Thermal Overload Relay
Specific Description:	Westinghouse Type AN Overload Relay with Heater Elements
Location:	Outside Containment
QDP:	Unit 2 QDP 72D
Methodology:	DOR Guidelines
TLAA Disposition Option:	Crit.(i): Valid for the Period of Extended Operation

The Westinghouse Type AN Overload Relay with Heater Elements are used in the Standby Gas Treatment System Control Panels.

Thermal

Aging was for 43 days @ 115°C. Activation energy was 0.96 eV (per the vendor report).

A service temperature of 108°F was established by adding 18°F heat rise in the panel to the 90°F design ambient which is deemed conservative (Ref.1).

Qualified life is 89 years.

Radiation

The specified 60-year total integrated dose is 1.5 E6 Rads. The test dose was 2.0 E6 Rads.

Equipment Qualification (EQ) Summary

Application Figure:	4.4-94
Commodity Type:	Contactor
Specific Description:	Allen Bradley 702LP-BOD93 Magnetic Latch Contactor
Location:	Outside Containment
QDP:	Unit 2 QDP 72G
Methodology:	DOR Guidelines
TLAA Disposition Option:	Crit.(i): Valid for the Period of Extended Operation

The Allen Bradley 702LP-BOD93 Magnetic Latch Contactor is used the Standby Gas Treatment System Control Panel.

Thermal

Aging was for 817 hours @ 235°F. The weak-link activation energy was 0.96eV for the phenolic (per the vendor report).

A service temperature of 108°F was established by adding 18°F heat rise in the panel to the 90°F design ambient which is deemed conservative (Ref.1).

Qualified life is 61.3 years.

Thermal

The specified 60-year total integrated dose is 1.5 E6 Rads, versus a test dose of 4.47 E7 Rads.

Equipment Qualification (EQ) Summary

Application Figure:	4.4-95
Commodity Type:	Terminal Blocks
Specific Description:	Buchanan 211 Terminal Blocks
Location:	Outside Containment
QDP:	Unit 2 QDP 72H
Methodology:	DOR Guidelines
TLAA Disposition Option:	Crit.(i): Valid for the Period of Extended Operation

The Buchanan 211 Terminal Blocks are used in the Standby Gas Treatment System Control Panels.

Thermal

Aging was for 817.37 hours @ 238°F. The activation energy is 2.28eV for the terminal block phenolic, per the vendor test report.

A service temperature of 108°F was established by adding 18°F heat rise in the panel to the 90°F design ambient which is deemed conservative (Ref.1).

Qualified life was calculated to be 750 years.

Radiation

The 60-year total integrated dose is 1.5 E6 Rads (Ref.2). The test dose was 4.47 E7 Rads.

Equipment Qualification (EQ) Summary

Application Figure:	4.4-97
Commodity Type:	Fuses
Specific Description:	Bussmann Type FNM-5 Dual Element Time Delay Fuse
Location:	Outside Containment
QDP:	Unit 2 QDP 72K
Methodology:	DOR Guidelines
TLAA Disposition Option:	Crit.(i): Valid for the Period of Extended Operation

The Bussmann Type FNM-5 Dual Element Time Delay Fuses are used in the Standby Gas Treatment System Control Panels.

Thermal

Aging was for 28 days @ 248°F. The activation energy is 1.56eV, per the vendor test report.

A service temperature of 108°F was established by adding 18°F heat rise in the panel to the 90°F design ambient which is deemed conservative (Ref.1).

Qualified life was calculated to be 6,898 years.

Radiation

The 60-year total integrated dose is 1.5 E6 Rads (Ref.2). The test dose was 2.0 E8 Rads.

Equipment Qualification (EQ) Summary

Application Figure:	4.4-98
Commodity Type:	Fuses and Fuseblocks
Specific Description:	Bussmann 4482 Fuse Blocks and Bussman AGS and AGC Fuses
Location:	Outside Containment
QDP:	Unit 2 QDP 72L
Methodology:	DOR Guidelines
TLAA Disposition Option:	Crit.(i): Valid for the Period of Extended Operation

The Bussmann 4482 fuse blocks and Bussman AGS and AGC fuses are qualified for use in the Standby Gas Treatment System Control Panels.

This summary applies only to the Bussman AGS and AGC fuses, which are qualified by material analysis. Qualification is valid for the period of extended operation.

Thermal

With the exception of the epoxy-based cement, all materials of construction are inorganic and not susceptible to thermal aging nor radiation degradation. Once rigidly mounted in the qualified fuse block, any degradation of the cement would not be expected to prevent the fuses from performing their function.

The activation energy for the fuse has been established to be 0.90eV, from a range provided for epoxy resin in the EPRI EQ Reference Manual.

A service temperature of 108°F was established by adding 18°F heat rise in the panel to the 90°F design ambient which is deemed conservative (Ref.1). The normal, LOCA, and post-LOCA environments will not subject the fuses to abnormal stresses and thermal degradation in the SGTS location. Therefore, the fuses are not considered susceptible to significant thermal degradation.

Radiation

The 60-year total integrated dose is 1.5 E6 Rads (Ref.2). The lowest reported radiation threshold for epoxy resin is 2.0 E8 Rads, per EPRI Publication NP-2129, "Radiation Effects of the Organic Materials in Nuclear Plants". The fuses have been tested to 1.5 E7 Rads prior to seismic testing, without any adverse effects.

Equipment Qualification (EQ) Summary

Application Figure:	4.4-99
Commodity Type:	Pilot Light
Specific Description:	Allen Bradley 800H & 800T Pilot Lights
Location:	Outside Containment
QDP:	Unit 2 QDP 72N
Methodology:	DOR Guidelines
TLAA Disposition Option:	Crit.(i): Valid for the Period of Extended Operation

The Allen Bradley 800H & 800T Pilot Light assemblies are used in the Standby Gas Treatment System.

Thermal

Aging was for 817.04 hours @ 235°F. The activation energy is 0.96eV, per the vendor test report.

A 90°F design ambient is used to calculate qualified life, and is deemed conservative (Ref.1).

Qualified life was calculated to be 196 years.

Radiation

The specified 60-year total integrated dose is 1.5 E6 Rads (Ref.2). The test dose was 4.47 E7 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-100

Commodity Type:	Internal Panel Wire
Specific Description:	American Insulated Wire Corporation and Triangle Wire Company XHHW 600 V Panel Wire
Location:	Outside Containment
QDP:	Unit 2 QDP 72O
Methodology:	DOR Guidelines
TLAA Disposition Option:	Crit.(i): Valid for the Period of Extended Operation

The American Insulated Wire Corporation and Triangle Wire Company XHHX 600 V Internal Panel Wire is used in the Standby Gas Treatment System Control Panels.

Thermal

Aging was for 711.05 hours @ 227°F. The activation energy is 1.10eV, per the vendor test report.

A service temperature of 108°F was established by adding 18°F heat rise in the panel to the 90°F design ambient which is deemed conservative (Ref.1).

Qualified life was calculated to be 93.5 years.

Radiation

The specified 60-year total integrated dose is 1.5 E6 Rads (Ref.2). The test dose was 1.5 E8 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-103

Commodity Type: Thermal Overload Relays with Heaters

Specific Description: Westinghouse Type AN Relay with FH Series Heater Element

Location: Outside Containment

QDP: Unit 2, QDP 72R

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit.(I): Valid for the Period of Extended Operation

Conclusion:

The Westinghouse Type AN Relay with FH Series Heater Element is qualified for use in the Standby Gas Treatment System Filter Train Room of Reactor Building Elevation185'.

Thermal

Aging was for 43 days @ 240°F. The activation energy of 0.96eV for the phenolic, per the vendor test report.

A service temperature of 108°F was established by adding 18°F heat rise in the panel to the 90°F design ambient which is deemed conservative (Ref. 1).

Qualified life was calculated to be 81 years.

Radiation

The specified 60-year total integrated dose is 1.5 E6 Rads (Ref. 2). The test dose was 2.8 E6 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-104

Commodity Type: Fuses

Specific Description: Bussmann Types AGS & AGC

Location: Outside Containment

QDP: Unit 2, QDP 72S

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

The Bussmann Types AGS & AGC fuses are qualified for use in the Standby Gas Treatment System Filter Train Room of Reactor Building Elevation 185'. The qualification is by test and material analysis.

Thermal

With the exception of the epoxy-based cement, all materials of construction are inorganic and not susceptible to thermal aging nor radiation degradation. Once rigidly mounted in the qualified fuse block, any degradation of the cement would not be expected to prevent the fuses from performing their function.

Activation energy for the fuse has been established to be 0.90eV, from a range provided for epoxy resin in the EPRI EQ Reference Manual.

A service temperature of 108°F was established by adding 18°F heat rise in the panel to the 90°F design ambient which is deemed conservative (Ref.1). The normal, LOCA, and post-LOCA environments will not subject the fuses to abnormal stresses and thermal degradation in the SGTS location. Therefore, the fuses are not considered susceptible to significant thermal degradation.

Radiation

The 60-year total integrated dose is 1.5 E6 Rads (Ref.2). The lowest reported radiation threshold for epoxy resin is 2.0 E8 Rads, per EPRI Publication NP-2129, "Radiation Effects of the Organic Materials in Nuclear Plants". The fuses have been tested to 1.5 E7 Rads prior to seismic testing, without any adverse effects.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-105

Commodity Type: Temperature Switches

Specific Description: Fenwal Models 27121-0-325 and 27121-0-190

Location: Outside Containment

QDP: Unit 2 QDP 73

Methodology: DOR Guidelines

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

The Fenwal Model 27121 thermoswitches are qualified for use in the Standby Gas Treatment System Filter Train Room of Reactor Building Elevation 185'.

Thermal

Aging was for 28 days @ 120°C. The activation energy is 1.14eV for the nylon braid, per the vendor test report.

The vendor established a qualified life of 418 years at 104°F. The normal design temperature for the area is 90°F (Ref.1), and is conservative.

Radiation

The specified 60-year total integrated dose is 3.0 E7 Rads maximum (Ref.2). The test dose was 2.0 E8 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-106

Commodity Type: Temperature Switches

Specific Description: Fenwal Models 18021-0

Location: Outside Containment

QDP: Unit 2, QDP 73A

Methodology: 10 CFR 50.49

TLAA Disposition Option: Crit.(i): Valid for the Period of Extended Operation

The Fenwal Model 18021-0 Temperature Switch is qualified for use in the Standby Gas Filter Train Room on Elevation 185' of the Reactor Building.

Thermal

Aging was for 28 days @ 120°C. The activation energy is 1.14eV for the nylon braid, per the vendor test report.

The vendor established a qualified life of 418 years at 104°F. The normal design temperature for the area is 90°F (Ref.1), and is conservative.

Radiation

The specified 60-year total integrated dose is 1.2 E6 Rads (Ref.2). The test dose was 2.0 E8 Rads.

Equipment Qualification (EQ) Summary

Application Figure: 4.4-107

Commodity Type:	Flow Switch
Specific Description:	McDonnell & Miller FS7-4V Flow Switch
Location:	Outside Containment
QDP:	Unit 2 QDP 74
Methodology:	DOR Guidelines
TLAA Disposition Option:	Crit.(i): Valid for the Period of Extended Operation

The McDonnell & Miller FS7-4V Flow Switches are used in the Standby Gas Treatment System. Qualification is by test and analysis.

Thermal

Aging was for 817 hours @ 235°F. The activation energy is 2.28eV for the phenolic, which is the only organic material found in the switch mechanism, per the vendor test report.

The normal design temperature for the area is 90°F (Ref.1), and is conservative.

Qualified life was calculated to be 7.5 E6 years.

Radiation

The specified 60-year total integrated dose is 6.21 E5 Rads (Ref.2). The test dose was 4.47 E7 Rads.

RAI 4.4-2:

Section 4.4.5 of the LRA lists various commodity types based on option (ii) of 10 CFR Part 54.21 (c)(1) to demonstrate that the analyses have been projected to the end of the period of extended operation. For each of the following selected commodity types, provide the Environmental Qualification (EQ) calculations that were used to project the qualified lives to the end of the period of extended operation:

a. 4.4-2 Limitorque SB, SMB Actuators, AC Service
b. 4.4-5 General Electric F01 Electrical Penetration Assemblies
c. 4.4-6 Amphenol Type HN Plug Connectors
d. 4.4-8 States ZWM and NT Series Terminal Blocks
e. 4.4-20 Raychem Breakout/Scotchcast 9 Potting Compound
f. 4.4-26 AMP Special Ind. Insulated/Uninsulated Terminals and Splices
g. 4.4-29 Okonite Low Voltage and Medium Voltage Power and Control Cables; and Instrumentation Cables
h. 4.4-32 Okonite T-95 Insulating and No. 35 Jacketing Tapes/Cement
i. 4.4-38 Anaconda Low Voltage Power, Control, and Instrumentation Cables
j. 4.4-52 GE RHR and Core Spray Pump Motors
k. 4.4-61 Brand-Rex Low Voltage Power, Control, and Instrumentation Cables and Internal Panel Wiring
l. 4.4-76 Conax Buffalo Electrical Penetrations
m. 4.4-79 Eaton (Samuel Moore) Instrumentation and Thermocouple Cables
n. 4.4-86 Reliance Motors FNA-6856 and 6857

RESPONSE TO RAI 4.4-2:

SNC met with the NRC at the NRC's offices on August 23 and 24, 2000, to present the calculations that NRC requested in this RAI. NRC prepared a meeting summary that was issued via electronic communication on August 31, 2000. The meeting summary indicated the staff's conclusions regarding the adequacy of the calculations will be provided in the SER.

RAI 4.5-1:

The applicant states that it identified one containment penetration structural analysis that assumed a number of pressurization cycles for 40 years. With regard to this particular analysis, provide the following information:

a. Identify this penetration with respect to its location, environment, number of thermal and pressurization cycles that it is assumed to undergo during the current licensing term, cycles that have actually occurred up to now, and cycles that are estimated until the end of the extended period of operation.

b. Provide a summary of the structural analysis, including the parameters and boundary conditions considered, to demonstrate the acceptability of using backing rings.

c. Are there other penetrations, in either unit, which can be identified as having the same characteristics from the standpoint of the cumulative usage factor (CUF)?

RESPONSE TO RAI 4.5-1:

This calculation applies to the Class B weld (ASME Section III, N-415.1, 1968 Edition) of the main steam penetration assembly to the containment, and justifies the use of a backing ring for that type and location of weld. Forty pressurization cycles to full design pressure were assumed in the calculation, and the calculation was revised to consider 60 pressurizations to full design pressure. This assumption is conservative, and therefore SNC has demonstrated the acceptability of the analysis in accordance with Criterion (ii) of 10CFR Part 54.21(c)(1). In addition, the calculation containing this TLAA is available at the SNC offices for NRC review.

RAI 4.5-2:

The Hatch containment drywell, torus, vent lines, penetrations, penetration bellows (including vent line bellows), and dissimilar metal welds in bellows undergo undefined numbers of thermal cycling (during reactor mode changes and transients), pressurization pulses during the SRV discharges, and pressure cycles during leak rate testing. The usage factors related to these components depend upon the number of thermal and pressurization cycles assumed in the current licensing basis (CLB), cycles actually experienced until now, and the estimated cycles until the end of the extended period of operation. Provide the following information, for both of the Hatch units, to justify the exclusion of these components from the TLAA.

a. A table showing the number of thermal and pressurization cycles and their ranges for each of the six component types (or commodity groups, if applicable), described above, corresponding to those cycles assumed in the CLB analyses, cycles experienced thus far, and cycles estimated to occur up to the end of the extended period of operation.

b. Provide the CUF corresponding to the estimated cycles in the CLB, the number of cycles experienced thus far, and the estimated number of cycles to occur up to the end of the extended period of operation.

RESPONSE TO RAI 4.5-2:

The information requested in this RAI is summarized in the design analysis SNC prepared to address fatigue in the torus. The design analysis is proprietary to SNC and is available in the SNC offices for NRC review.

RAI 4.5-3:

List all containment penetrations with pipe-to-penetration welds.

RESPONSE TO RAI 4.5-3:

See the response to RAI-4.5-4.

RAI 4.5-4:

For the containment penetrations with pipe-to-penetration welds, provide a justification as to why TLAAs were not performed considering the pressurization cycles and cyclic thermal expansion of the attached piping.

RESPONSE TO RAI 4.5-4:

SNC reviewed the Plant Hatch current licensing basis and found no analyses on this subject that met the definition criteria of 10 CFR Part 54.3 for a TLAA.

RAI 4.6-1:

Sections 4.6.3 and A.1.17.1 of the LRA discuss ultrasonic inspection of the Hatch RPV circumferential welds. Section A.1.17.1,"The Reactor Pressure Vessel Monitoring Program," indicates that Hatch will use an approved technical alternative in lieu of ultrasonic testing of RPV circumferential shell welds. The technical alternative is discussed in the staff's final SER, dated July 28, 1998, of the BWR Vessel and Internals Project BWRVIP-05 Report, "BWR RPV Shell Weld Inspection Recommendations," September, 1995. Section A.4.5 of Report BWRVIP - 74, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," indicates that the SER conservatively evaluated BWR RPV's to 64 effective full power years (EFPY), which is 10 EFPY greater than what is realistically expected for the end of the license renewal period. Since this was a generic analysis, the applicant must provide plant-specific information to demonstrate that the Hatch beltline materials meet the criteria specified in the report and operator training and procedures will be utilized during the license renewal term to limit the frequency for cold over-pressure events. To demonstrate that the vessel has not been embrittled beyond the basis for the technical alternative and that cold over-pressure events are not likely to occur during the license renewal term, the applicant must provide: (1) a comparison of the neutron fluence, initial RT_{NDT}, Chemistry Factor, amounts of copper and nickel, delta RT_{NDT} and Mean RT_{NDT} of the limiting Hatch circumferential weld at the end of the renewal period to the 64 EFPY reference case in Appendix E of the staff's SER, (2) an estimate of conditional failure probability of the RPV at the end of the license renewal term based on the comparison of the Mean RT_{NDT} for the limiting Hatch circumferential weld and the reference case, and (3) identify procedures and training that will be utilized during the license renewal term to limit the frequency of cold over-pressure events to the amount specified in the staff's SER.

RESPONSE TO RAI 4.6-1:

The information requested for Units 1 and 2 is in Appendix E of the Plant Hatch LRA. The limiting circumferential weld properties from Tables 3-1 and 3-2 of LRA Appendix E are compared to the information in Table 2.6-4 and Table 2.6-5 from the staff SER on BWRVIP-05.

The NRC staff used materials and fluence data in Tables 2.6-4 and 2.6-5 to evaluate failure probability of BWR circumferential welds at 32 and 64 EFPY. The Mean RT_{NDT} used by the NRC have been compared to the Plant Hatch values (54 EFPY ART in Plant Hatch tables) from Appendix E of the LRA. The Unit 1 values at 54 EFPY are essentially equal to or less than the staff analysis for 32 EFPY. The Unit 2 values at 54 EFPY are bounded by the 32 EFPY analysis by the NRC. The Unit 1 and 2 values at 54 EFPY are bounded by the 64 EFPY Mean RT_{NDT} by at least 25 °F. Although a conditional failure probability has not been calculated, the fact that the Plant Hatch 54 EFPY value is less than the 64 EFPY value the staff used leads to the conclusion that the Plant Hatch RPV conditional failure probability is bounded by the NRC analysis.

The procedures and training used to limit cold over-pressure events will be the same as that approved by NRC when Plant Hatch requested the BWRVIP-05 technical alternative be used for current term. There is nothing unique about the renewal term in this regard.

Circumferential Weld

Group	**CE (VIP) 32 EFPY**	**CE (CEOG) 32 EFPY**	**CE (VIP) 64 EFPY**	**CE (CEOG) 64 EFPY**	**Hatch 1 54 EFPY**	**Hatch 2 54 EFPY**
Cu%	0.13	0.183	0.13	0.183	0.197	0.047
Ni%	0.71	0.704	0.71	0.704	0.060	0.049
CF	151.7	172.2	151.7	172.2	91.0	31.0
Fluence (10^{19}n/cm$^{2)}$	0.20	0.20	0.40	0.40	0.171	0.177
ΔRT_{NDT} (°F)	86.4	98.1	113.2	128.5	96.9	33.5
$RT_{NDT(U)}$ (°F)	0	0	0	0	-10	-50
Mean RT_{NDT} (°F)	86.4	98.1	113.2	128.5	86.9	-16.5
P(F/E) NRC	2.81 E-5	6.34 E-5	1.99 E-4	4.38 E-4	---	---
P(F/E) BWRVIP	No failure	---	---	---	---	---

RAI 4.6-2:

The staff's SER, contained in a letter to Carl Terry dated March 7, 2000, discusses the staff's concern related to RPV failure frequency for axial welds and the BWRVIP's analysis of the RPV failure frequency of axial welds. The SER indicates that the RPV failure frequency due to failure of the limiting axial welds in the BWR fleet at the end of 40 years of operation is below 5 x 10^{-6} per reactor year, given the assumptions on flaw density, distribution and location described in the SER. Since the BWRVIP analysis was generic, the applicant must provide plant-specific information to demonstrate that the Hatch beltline materials meet the criteria specified in the report and operator training and procedures will be utilized during the license renewal term to limit the frequency for cold over-pressure events. To demonstrate that the vessel has not been embrittled beyond the basis for the staff and BWRVIP analyses, the applicant must provide: (1) a comparison of the neutron fluence, initial RT_{NDT}, Chemistry Factor, amounts of copper and nickel, delta RT_{NDT} and Mean RT_{NDT} of the limiting Hatch axial weld at the end of the renewal period to the reference cases in the BWRVIP and staff analyses and (2) an estimate of conditional failure probability of the RPV at the end of the license renewal term based on the comparison of the Mean RT_{NDT} for the limiting Hatch axial welds and the reference case. If this comparison does not indicate that the RPV failure frequency for axial welds is less than 5 x 10^{-6} per reactor year, provide a probabilistic analysis to determine the RPV failure frequency for axial welds.

RESPONSE TO RAI 4.6-2:

The information requested for Units 1 and 2 is in Appendix E of the LRA. In the following table, the limiting axial weld properties from Tables 3-1 and 3-2 of Appendix E are compared to the information in Table 2.6-4 and Table 2.6-5 from the staff SER on BWRVIP-05. A comparison of the Mean RT_{NDT} values from the NRC report with the Plant Hatch data (54 EFPY ART in the Appendix E tables) shows that the NRC analysis bounds the Plant Hatch welds. Although a conditional failure probability has not been calculated, the fact that the Plant Hatch 54 EFPY value is less than the 64 EFPY value the staff used leads to the conclusion that Plant Hatch is bounded by the NRC analysis.

Table

Axial Weld

Group	CE (VIP) 32 EFPY	CE (CEOG) 32 EFPY	CE (VIP) 64 EFPY	CE (CEOG) 64 EFPY	Hatch 1 54 EFPY	Hatch 2 54 EFPY
Cu%	0.26	0.219	0.26	0.219	0.316	0.216
Ni%	1.20	0.996	1.20	0.996	0.724	0.043
CF	276.0	231.1	276.0	231.1	219.0	98.0
Fluence (10^{19}n/cm^{2})	0.15	0.20	0.30	0.40	0.251	0.167
ΔRT_{NDT} (°F)	138.8	131.6	185.0	172.4	192.9	103.3
$RT_{NDT(U)}$ (°F)	-20	0	-20	0	-50	-50
Mean RT_{NDT} (°F)	118.8	131.6	165.0	172.4	142.9	53.3
P(F/E) NRC	2.94 E-1	4.37 E-1	7.49 E-1	8.28E-1	---	---
P(F/E) BWRVIP	1.37 E-2	---	---	---	---	---

RAI 4.6-3:

The BWRVIP analysis in BWRVIP-74 was a bounding analysis for Charpy USE. For BWR/4 RPVs this analysis indicates that at 54 EFPY the Charpy USE in the transverse direction would be at least 45 ft-lb and the Charpy USE for the non-Linde 80 submerged arc welds (SAWs) would be at least 43 ft-lb. Since this was a generic analysis, the applicant must provide plant-specific information to demonstrate that the Hatch beltline materials meet the criteria specified in the report at the end of the license renewal period. The applicant must provide the information specified in Tables B-4 and B-5 of EPRI-113596.

RESPONSE TO RAI 4.6-3:

The requested information is in Appendix E of the LRA. In each case, the Plant Hatch materials are bounded by the generic analysis. However, the forms used to report the information were not correct. The Plant Hatch results were reported on forms used in the original equivalent margins topical report for a 40-year life. The correct forms to use are contained in BWRVIP-74, as noted by the staff. The corrected information is contained below.

In Table 3-3 of Appendix E, the Unit 1 limiting plate predicted decrease in USE should be compared with the BWR/3-6 value of 23.5% (not 21%) from BWRVIP-74. The predicted shift for the limiting beltline plate is 19%, and is therefore bounded by the generic analysis.

In Table 3-4 of Appendix E, the Unit 1 limiting weld predicted decrease in USE should be compared with the BWR/2-6 value of 39% (not 34%) from BWRVIP-74. The predicted shift for the limiting weld is 33%, and is therefore bounded by the generic analysis.

In Table 3-5 of Appendix E, the Unit 2 limiting plate predicted decrease in USE should be compared with the BWR/3-6 value of 25.5% (not 21%) from BWRVIP-74. The predicted shift for the limiting beltline plate is 15%, and is therefore bounded by the generic analysis

In Table 3-6 of Appendix E, the Unit 2 limiting weld predicted decrease in USE should be compared with the BWR/2-6 value of 39% (not 34%) from BWRVIP-74. The predicted shift for the limiting weld is 24%, and is therefore bounded by the generic analysis.

RAI 4.6-4:

Provide peak neutron fluences at the inside surface of the RPVs. Provide your methodology for determining the neutron fluence and include the calculational procedure, cross sections, neutron sources, approximations, and use of dosimetry, if applicable.

RESPONSE TO RAI 4.6-4:

As presented in Appendix E of the Plant Hatch LRA, the 54 EFPY peak fluence values are 3.47×10^{18} n/cm^2 and 3.82×10^{18} n/cm^2 at the vessel wall for Units 1 and 2, respectively. These fluences were determined by taking the fluence at 32 EFPY associated with the approved extended power uprate and adding to it the fluence that would accumulate during an additional 22 EFPY of operation at the flux associated with the extended power uprate conditions.

RAI 4.7-1:

In Section 4.7 of the LRA, the applicant stated that the operating cycles of the main steam isolation valves (MSIVs) are assumed to be 2050 cycles for 40 years in the Plant Hatch Updated Final Safety Analysis Report (FSAR). The applicant also indicated that cycling of the valve will lead to wear of the valve disc and valve seat that will accumulate over time. On this basis, the applicant identified MSIV operating cycles as a TLAA. The applicant further indicated that this kind of wear due to operation of the valve will lead to performance degradation, discoverable through TS leakage monitoring testing. Excessive leakage would lead to refurbishment or repair of the valve seat and disc, as necessary. The applicant dispositioned that TLAA through Criterion (iii) of 10 CFR 54.21(c)(1).

Under this disposition option, demonstrate that the effects of aging on the component intended functions will be adequately managed consistent with the CLB for the period of extended operation. In addition, the FSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging and the evaluation of the TLAA for the period of extended operation.
Sufficient information was not provided as described in 10 CFR 54.21(c)(1)(iii). Identify all the components that may be subjected to the effects of wear aging/cyclic fatigue (e.g., valve disc, valve seat, stem, diaphragm, positioner). Also, discuss all the applicable effects of aging (e.g., excessive leakage, exceeding TS-specified valve closure time) on the MSIVs intended functions. In addition, to ensure that the effects of aging will be adequately managed, provide sufficient information related to the referenced testing and maintenance/repair program, including objectives of the testing, parameters monitored or inspected, frequency of testing, detection of aging effects, acceptance criteria, corrective action, and operating experience to demonstrate that the program will effectively manage the applicable aging effects. Furthermore, revise Sections A.4.1 and A.4.1.1 of the LRA to include a summary discussion of the MSIV operating cycles TLAA, in accordance with 10CFR 54.21(c)(1) (iii).

RESPONSE TO RAI 4.7-1:

At the time of submittal, GE had been unable to fully determine the basis for the MSIV cycles in the FSAR. Therefore, as a conservative measure, SNC identified the MSIV cycles in the FSAR as a TLAA. Since that time, GE has determined that the number is derived from a specification, not from a calculation or analysis. Thus, SNC has now confirmed that the MSIV cycles referenced in the FSAR is not a TLAA. Since the cycles are specified against the active features of the valve and not the valve body, there is no specific program that falls under the purview of the Rule processes.

However, SNC also notes that the MSIVs have extensive testing programs. There are containment isolation testing and valve stroking requirements, which can be found in Technical Specification 3.6.1.3. Plant Hatch has inspection procedures to address the wear of the stellite faces. Plant Hatch periodically disassembles and refurbishes the valves. The solenoid valves and limit switches on the valves also are routinely replaced or completely refurbished to address environmental qualification requirements. There are also other repetitive tasks on the valves, such as replacing the actuator hydraulic fluid every 54 months and inspecting the wiring every 36 months.

VI. APPENDIX B

EDWIN I. HATCH NUCLEAR PLANT

DOCKETS 50-321, 50-366

OPERATING LICENSES DPR-57, NPF-5

APPENDIX B

LICENSE RENEWAL APPLICATION

RESPONSE TO REQUESTS FOR ADDITIONAL INFORMATION

RELATED TO AGING MANAGEMENT REVIEWS

AND AGING MANAGEMENT PROGRAMS

DATED JULY 14, 2000 AND JULY 28, 2000

Table of Contents

B.1 EXISTING PROGRAMS AND ACTIVITIES

The Corrective Action 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.

See Section B.1.8 for a description of how attributes 7, 8, and 9 above are met for all programs. Specific operating experience (Attribute 10) is discussed for each individual program or activity.

B.1.1 Reactor Water Chemistry Control

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, reliability, and availability of plant systems and components by controlling fluid purity and composition.

The principal elements of Reactor Water Chemistry Control at Plant Hatch are regular sampling, results analysis and, when applicable, chemistry modification. These activities are further supported by trending, tracking and regular evaluations.

Control of reactor water chemistry is accomplished in accordance with EPRI TR-103515. Currently, reactor coolant system chemistry standards are met through the use of filtration and ion exchange operations accomplished by powdered resin condensate polishers. These condensate polishers effectively limit concentrations of suspended solids and ionic impurities within the reactor coolant. Hydrogen injection and NMCA may be utilized to further reduce the ECP of reactor water. HWC reduces the oxidizing potential of the coolant by maintaining residual dissolved hydrogen content. This excess hydrogen reacts with radiolytically produced oxygen and hydrogen peroxide, thereby limiting the concentrations of these oxidizing species in reactor water. NMCA injects noble metals such as platinum and rhodium that act as catalysts for the recombination reactions and allow effective use of lower residual dissolved hydrogen concentrations. Lower ECP values produced by implementation of HWC and NMCA have been shown to mitigate corrosion within reactor coolant systems.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

Portions of the following systems, structures and components are directly or indirectly monitored by reactor water chemistry control:

B11 – Reactor Assembly
B21 – Nuclear Boiler
B31 – Reactor Recirculation
E41 – HPCI
E51 – RCIC
N32 – EHC
N61 – Main Condenser System

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

Components subjected to a reactor water environment are fabricated from carbon steels, low alloy steels, stainless steels, and nickel based alloys. By controlling reactor water chemistry, Plant Hatch IGSCC in reactor cooling system piping and reactor internals, IASCC within the beltline region components, and other types of corrosion throughout systems containing reactor water.

Reactor water chemistry control is directed at minimizing the oxidizing power of the reactor water. EPRI TR-103515 provides technical data linking reduced coolant-oxidizing power to a commensurate reduction in IGSCC, IASCC, and other corrosion processes.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

EPRI TR-103515 provides the basis for the reactor coolant chemistry parameters monitored to ensure adequate chemistry control at Plant Hatch. These parameters include coolant conductivity, sulfate concentrations, and chloride concentrations. Currently, when HWC is in service, ECP is also monitored.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

Reactor water chemistry control is a mitigative activity and as such is not intended to directly detect age-related degradation of reactor assembly and reactor coolant system components.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Reactor Water Chemistry Control does not directly monitor or trend age related degradation and as such is not credited to perform this attribute in the Plant Hatch LRA.

However, EPRI TR-103515 provides the basis for the methodology employed for trending, tracking, and regular evaluations of reactor water chemistry parameters. During normal power operations, sulfates and chlorides are monitored daily, and conductivity is continuously monitored. Currently ECP is continuously monitored when hydrogen injection is in service.

Acceptance Criteria

(Acceptance criteria are included.)

Acceptance criteria for reactor water chemistry control are based on an approved version of EPRI TR-103515. This document specifies chemistry control parameters and associated action levels, sample frequencies, and analysis methods for adequate reactor water chemistry control. Chemistry control parameters and sample frequencies specified in EPRI TR-103515 are based on plant operating conditions and the water chemistry mode currently in use (normal water chemistry without hydrogen injection or HWC).

During normal power operations, reactor coolant chemistry is maintained in accordance with the minimum reactor water control parameters (action level 1) contained within EPRI TR 103515 Rev. 2. The minimum control parameters are:

Conductivity:	$< 0.30\ \mu S/cm$
Chlorides:	< 5 ppb
Sulfates:	< 5 ppb

These parameters, and associated acceptance criteria, are applicable for both HWC and normal water chemistry operations.

Currently, ECP is continuously monitored by sensors contained within the reactor vessel drain line, whenever hydrogen injection is in service, to verify the continued effectiveness of HWC and NMCA.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

EPRI TR-103515 considers historical data collected from industry and contains lessons learned from many years of operating experience, thereby assuring that past experience, including that experience gained via BWRVIP activities has been utilized to improve the program methods.

Plant Hatch has aggressively pursued improvements in aging management of in-scope components through improved chemical control methods, sampling and measurement techniques, and installation of new equipment designed to mitigate aging effects. These improvements have been based on the EPRI BWR water chemistry program outlined in EPRI TR-103515.

After encountering significant problems with IGSCC in recirculation system large bore stainless steel piping, Plant Hatch was among the first plants to install hydrogen water chemistry equipment. The HWC system was installed to reduce the ECP of the reactor coolant, thereby effectively eliminating the environmental conditions conducive to IGSCC within reactor recirculation system piping and reducing the potential for IGSCC and IASCC in susceptible reactor assembly components.

NMCA was added to Unit 1 during the 1999 refueling outage and added to Unit 2 during the 2000 refueling outage. NMCA serve to catalyze the recombination of oxygen and hydrogen peroxide with hydrogen, thereby reducing the hydrogen injection rates required to maintain acceptably low reactor coolant ECP values.

References

1. *Edwin I. Hatch Nuclear Plant Technical Requirements Manual, Units 1 and 2.*

2. *TR-103515, Electric Power Research Institute (EPRI), "BWR Water Chemistry Guidelines".*

3. *TR-112214, Electric Power Research Institute (EPRI), "BWR Vessel and Internals Project, Proceedings: BWRVIP Symposium, November 12-13, 1998"*

4. *TR-108705, Electric Power Research Institute (EPRI), "BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection"*

B.1.2 Closed Cooling Water Chemistry Control

CCW chemistry control is a mitigating activity designed to maintain structural integrity, reliability, and availability of plant closed cooling water systems and components by controlling fluid purity and composition.

The principal elements of CCW chemistry control at Plant Hatch are regular sampling, results analysis and, when applicable, chemistry modification. These activities are further supported by trending, tracking and regular evaluations.

EPRI TR-107396 currently provides a basis for the methodology employed to maintain CCW system chemistry parameters within acceptable limits, ensure adequate sampling frequencies, and specify proper analysis techniques.

Control of CCW chemistry is accomplished through the use of corrosion inhibitor additions, biocide additions, and chemical additions to control pH. Concentrations of detrimental impurities are diagnostically monitored. Should CCW chemistry parameters exceed the recommendations established by EPRI, appropriate actions to minimize the potential for significantly increased corrosion rates will be accomplished in accordance with the Plant Hatch corrective actions program.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

While CCW chemistry control is applicable to all closed cycle cooling water systems, only limited portions of CCW systems are within the scope of license renewal. Operation of these systems is not vital to the safe shutdown of the plant under normal or accident conditions. However, certain portions of these systems are in scope to maintain primary containment integrity. Portions of the following systems are included:

P42 – RBCCW
P64 – PCCW
(P64 is applicable to Unit 2 only)

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

Components subjected to a CCW environment are fabricated from carbon steels, stainless steels, and copper based alloys. By controlling chemistry in CCW systems, loss of material due to corrosion and microbiological influences may be mitigated. Corrosion inhibitors promote the formation of adherent oxide layers on system components to reduce overall corrosion rates. Biocide additions provide for control of microbe populations – thereby reducing corrosion due to the influence of biological activity.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

EPRI TR-107396 provides the basis for CCW chemistry chemical additions and monitoring to ensure adequate chemistry control at Plant Hatch. This guideline provides several different treatment options and provides recommendations for applicable control parameters.

Chemical additions include, nitrite / molybdate additions to inhibit carbon steel corrosion and TTA additions to inhibit copper alloy corrosion. EPRI-recommended biocide additions are utilized to control microbe populations. Application of these biocides is based on the results of microbiological analyses and is varied to maximize the effectiveness of additions on microbiological populations while minimizing the effects on other chemical parameters.

Control parameters include pH (proper pH reduces corrosion rates and increases corrosion inhibitor effectiveness) and corrosion inhibitor concentrations. Diagnostic parameters evaluated include biocide concentrations and microbe populations; ammonia, chloride, and sulfate concentrations; and conductivity.

Additionally, RBCCW systems contain carbon steel corrosion coupons, which are analyzed periodically to verify the effectiveness of the corrosion inhibitor system.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

CCW chemistry control is a mitigative activity and as such is not intended to directly detect age-related degradation of components subjected to closed cooling water.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

CCW chemistry control does not directly monitor or trend age related degradation and as such is not credited to perform this attribute within the Hatch license renewal application. However, EPRI TR-107396 provides the basis for the methodology employed for trending, tracking, and regular evaluations of closed cooling water chemistry parameters at Plant Hatch. Engineering personnel assist in performing evaluations of the structural integrity of the in scope plant systems. When necessary, chemistry modification is performed.

Currently, Na_2MoO_4, $NaNO_2$ and pH are monitored weekly; TTA is monitored bi-weekly; sulfates, chlorides, and bacteria populations are monitored monthly; and carbon steel corrosion coupons are weighed semiannually.

Acceptance Criteria

(Acceptance criteria are included.)

Acceptance criteria for CCW chemistry control are based on an approved version of EPRI TR-107396. This document specifies appropriate parameter limitations, and analysis methods for adequate CCW chemistry control.
The following acceptance criteria apply:

Sulfates:	< 10 ppm
Chlorides:	< 10 ppm
pH:	8.8 – 10.0
Na_2MoO_4	300 < X < 500 ppm
$NaNO_2$	300 < X < 500 ppm
TTA	> 25 ppm

In addition to the specific acceptance criteria shown above bacteria populations are monitored monthly to validate the effectiveness of biocide additions and provide a basis for ongoing additions of two biocides; glutaraldehyde and isothiazolone.

Finally, carbon steel corrosion coupons are weighed on a semiannual basis to ensure that corrosion rates occurring within CCW systems is not significant. EPRI TR-107396 target values for carbon steel coupons are less than 0.2 mpy for an excellent rating and less than 0.5 mpy for a good rating.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

EPRI TR-107396 considers historical data collected from industry and contains lessons learned from many years of operating experience, thereby assuring that past experience has been utilized to improve the program methods.

The CCW chemistry approach has been improved through lessons learned during operation at Plant Hatch. Corrosion inhibitor systems and biocide additions have been modified based on various past problems and industry data to improve CCW system chemistry stability.

References

1. *TR-107396, EPRI Closed Cooling Water Chemistry Guidelines*

2. *CY 3973, Problems Observed in Closed Cooling Water System Chemistry Control and Monitoring Practices During INPO Evaluations*

3. *Edwin I. Hatch Nuclear Plant Final Safety Analysis Report, Unit 2*

B.1.3 Diesel Fuel Oil Testing

Fuel oils in their pure form are non-aggressive and non-corrosive for all metals. However, water in fuel oil, naturally occurring contaminants, and fuel oil additives can produce a corrosive environment.

Plant Hatch diesel fuel oil testing includes activities designed to prevent or mitigate loss of material from diesel fuel oil storage and transfer components due to intrusion of water or other contaminants.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

The Plant Hatch Diesel Fuel Oil Testing Program applies to the emergency diesel generator fuel oil storage tanks, the diesel generator fuel oil day tanks, and the associated transfer piping and components. It additionally covers the in-scope fire pump diesel fuel oil storage tanks and the associated piping and components. The following systems are within the scope of diesel fuel oil testing.

Y52 – Fuel Oil
X43 – Fire Protection

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The Plant Hatch Diesel Fuel Oil Testing Program activities provide for detection of water or other contaminants before loss of material can impact component function. Program elements include not only sampling and analysis of new fuel, but periodic sampling and analysis of fuel oil in storage and day tanks.

To prevent introduction of contaminated oil into Plant Hatch systems, new oil delivered in trucks is sampled before off loading. New fuel that does not pass a clear and bright test is analyzed for water and sediment prior to acceptance. Biocide is added during the off loading. The addition of a biocide, when properly controlled, minimizes the potential for microorganism growth and the potential for microbiologically influenced corrosion.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

Stored fuel oil is sampled for water content and total particulate. Minimization of these contaminants will prevent excessive corrosion within fuel oil systems.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

Diesel fuel oil testing is a mitigative activity and as such is not intended to directly detect age-related degradation of diesel fuel oil supply system components.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Diesel fuel oil testing does not directly monitor or trend age related degradation and as such is not credited to perform this attribute within the Hatch license renewal application. Maintaining fuel oil quality is sufficient to provide adequate aging management for associated tanks and other system components.

Acceptability of new fuel oil is determined by sampling and analysis prior to addition to the storage tanks to ensure that the fuel oil was not contaminated with other products in transit.

Stored fuel oil total particulate concentration is sampled once per quarter. This includes the EDG storage tanks and fire pump storage tanks.

Stored fuel oil water and sediment concentration is monitored both quarterly and semiannually as described under acceptance criteria.

Acceptance Criteria

(Acceptance criteria are included.)

The acceptance criteria for water and sediment content of new fuel oil shipments is < 0.05% by volume, if testing is required.

For EDG storage tanks, EDG day tanks, and fire pump diesel fuel oil storage tanks, the following acceptance criteria apply:

- As required by Technical Specification 5.5.9.b and Fire Hazards Analysis, Appendix B, SR 2.3.2.b, total particulate within stored fuel oil is 10mg/l or less.
- A three level composite sample from the EDG storage tank for water and sediment content is 0.05% or less by volume (monitored quarterly).
- A middle sample from the fire pump diesel fuel oil storage tanks for water and sediment content is 0.05% or less by volume (monitored quarterly).
- A bottom sample content from the EDG storage tanks, EDG day tanks, and fire pump diesel fuel oil storage tanks for water and sediment is 0.1% or less by volume (monitored semiannually).

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

A review of plant deficiency cards submitted over the past 5 years showed that several deficiencies were written on the applicable systems. These deficiencies were screened to determine which ones might be potentially age-related. Deficiencies related to the diesel fuel oil supply systems were limited to instances of unacceptable sediment and water levels within the EDG storage tanks and fire diesel fuel oil storage tanks. Acceptable levels were restored promptly through the corrective actions program. No instances of component failure due to age related degradation were identified.

References

1. *Edwin I. Hatch Nuclear Plant Technical Specifications, Units 1 and 2.*

2. *Edwin I. Hatch Nuclear Plant, Units 1 and 2 Fire Hazards Analysis and Fire Protection Program.*

B.1.4 Plant Service Water And RHR Service Water Chemistry Control

PSW and RHRSW chemical control activities are intended to reduce service water system corrosion rates and minimize biofouling of system components through a biocide application program using sodium hypochlorite alone or in conjunction with sodium bromide. The operation of the program is controlled by plant procedures.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

Service water chlorination and bromination mitigate aging within the following systems:

E11 – RHRSW
P41 – PSW

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

Sodium hypochlorite alone or in conjunction with sodium bromide is periodically added to PSW systems to control biological growth in the service water systems. Additionally, this program is coordinated with the periodic operation of RHRSW to maximize chemical treatment in this system since it is not continuously operated. Program feed rates, chemical concentrations, and duration are designed to ensure biological activity is minimized within the service water system components.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

During plant PSW system chlorination and bromination, free available oxidant concentration is periodically monitored at the PSW discharge to the circulating water flume to ensure program efficacy. The Plant Hatch NPDES Permit requires weekly monitoring of plant effluent to the Altamaha River for residual oxidant.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

PSW and RHRSW chemistry control is a mitigative activity and as such is not intended to directly detect age-related degradation of PSW and RHRSW system components.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Chemical additions to the PSW and RHRSW systems do not directly monitor or trend age related degradation and as such are not credited to perform this attribute within the

Plant Hatch LRA. However, the chemical additions under consideration are monitored routinely as described below:

Normally, the PSW system is chlorinated and/or brominated five times per week for a duration of 6 to 12 hours. FAO is monitored during the treatment cycle. This sample provides a reasonable assurance that sufficient biocide is being added to meet the system chlorine demand and result in an effective residual free available oxidant concentration. Sample results also provide indication that the program is operated consistent with the requirements and limitations of the Plant Hatch NPDES permit.

The Plant Hatch NPDES Permit requires weekly monitoring of the final plant effluent to the Altamaha River for residual oxidant. This data is reported quarterly.

Acceptance Criteria

(Acceptance criteria are included.)

During chlorination and bromination, plant service water effluent samples should indicate a resultant free available oxidant concentration exceeding 0.2 ppm, but generally less than 0.5 ppm, as measured at the PSW system discharge to the circulation water flume.

In accordance with the Plant Hatch NPDES Permit, the final plant effluent to the Altamaha River is sampled weekly. If the sample results indicate the presence of any residual oxidant, the sample is repeated every fifteen minutes until no residual oxidant is detected. These sample results are reported to the State of Georgia Department of Natural Resources on a quarterly basis.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

Plant Hatch has experienced biofouling problems with algae and has found evidence of the Asiatic clam. Algae are believed to be a primary cause of blockage within cooling tower fill bundles and fouling of cooling tower screens. Asiatic clams have been found in the intake structure and circulating water flumes. While these organisms have not yet resulted in significant problems within service water systems, the potential for significant biological fouling does exist in the absence of service water system biocide additions.

Current implementation of service water system chlorination and bromination is consistent with the recommendations of Generic Letter 89-13 regarding chlorination of service water systems and incorporates industry guidance, vendor recommendations, and plant specific experience. Chemical selection and application techniques are periodically evaluated and adapted to optimize control of biofouling while maintaining discharges to the Altamaha River within the limitations specified by the Plant Hatch NPDES permit.

References

1. *Plant Hatch Environmental Protection Plan, Units 1 and 2.*

2. *Generic Letter 89-13 with Supplement 1 "Service Water System Problems Affecting Safety-Related Equipment," 1990.*

3. *State of GA Department of Natural Resources Environmental Protection Division Permit No. GA0004120, "Plant Hatch NPDES Permit", Effective September 15, 1997.*

B.1.5 Fuel Pool Chemistry Control

Fuel pool chemical control is a mitigating activity designed to maintain structural integrity, reliability, and availability of plant systems and components by controlling fluid purity and composition.

The principal elements of fuel pool chemical control at Plant Hatch are regular sampling, results analysis and, when applicable, chemistry modification.

EPRI document TR-103515 "BWR Water Chemistry Guidelines" currently provides the basis for the methodology employed to maintain fuel pool chemistry parameters within acceptable limits, ensure adequate sampling frequencies, and specify proper analysis techniques.

Control of fuel pool chemistry is presently maintained through the use of filtration and ion exchange operations accomplished by filter/demineralizers. This process limits concentrations of suspended solids and ionic impurities within the fuel pool. Should fuel pool water chemistry parameters exceed the limitations established by EPRI, appropriate actions will be taken to minimize the potential for significantly increased corrosion rates and restore fuel pool purity.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

The Plant Hatch fuel pool chemical control activities are applicable to in-scope stainless steel and aluminum components exposed to the spent fuel pool water environment. These components include the stainless steel liners for the spent fuel pool, spent fuel pool plugs, spent fuel pool gate, and the refueling canal. Other stainless steel components within the scope of license renewal includes the spent fuel pool storage racks, miscellaneous steel inside the spent fuel pool, and the leak chase system. Aluminum components within the scope of license renewal include the seismic restraints for the spent fuel storage racks and the countersunk head screws for fuel/control rod handling. All of these components and structures are part of T24 (Fuel Storage).

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

Fuel pool and associated internal structures are primarily fabricated from stainless steels and aluminum alloys. Chemistry control is focused upon minimizing detrimental ionic species and conductivity. By controlling water chemistry in the fuel pool, Plant Hatch reduces the potential for significant corrosion of plant systems and components exposed to a fuel pool environment.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

EPRI TR-103515 provides the basis for fuel pool chemistry parameters monitored to ensure adequate chemistry control at Plant Hatch. Fuel pool chemistry diagnostic parameters regularly monitored include conductivity, chloride and sulfate concentrations, and total organic carbon levels. Control of these parameters will reduce the potential for significant corrosion. In addition, fuel pool pH and filterable solids concentration are diagnostically monitored.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

Fuel pool chemistry control is a mitigative activity and as such is not intended to directly detect age-related degradation of the fuel pool and associated internal structures.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Fuel pool chemistry control does not directly monitor or trend age related degradation and as such is not credited to perform this attribute within the Hatch license renewal application.

However, EPRI TR-103515 provides the basis for the methodology employed for periodic monitoring of fuel pool chemistry parameters at Plant Hatch. Sulfates, chlorides, conductivity, and total organic carbon are monitored weekly per EPRI TR-103515. In addition, fuel pool pH and filterable solids content is also regularly monitored.

Acceptance Criteria

(Acceptance criteria are included.)

EPRI TR-103515 provides diagnostic parameters and associated limitations for fuel pool chemistry analyses. Specific acceptance criteria included within EPRI TR-103515 are as follows:

Sulfates	< 100 ppb
Chlorides	< 100 ppb
Conductivity	< 2 μS/cm
Total Organic Carbon	< 400 ppb

In addition to the EPRI requirements shown above, pH and filterable solids are diagnostically monitored.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

A review of plant deficiency cards submitted over the past 5 years showed that no age related deficiencies have been written on the fuel pool or associated internal structures.

EPRI TR-103515 guidelines for auxiliary systems incorporate the input of industry experts and utility experience. Therefore, operation according to the guidelines specified by EPRI TR-103515 ensures that pertinent industry issues were considered.

Finally, fuel pool chemistry excursions have been rare in the past. In the past five years, only minor excursions above the criteria specified within EPRI TR-103515 have occurred. None of these excursions were determined to be significant.

References

1. *TR-103515, Electric Power Research Institute (EPRI), "BWR Water Chemistry Guidelines".*

B.1.6 Demineralized Water And Condensate Storage Tank Chemistry Control

Demineralized water chemical control is a mitigating activity designed to maintain structural integrity, reliability, and availability of plant systems and components by controlling fluid purity and composition.

The principal elements of demineralized water chemical control at Plant Hatch are regular sampling, results analysis and, when applicable, chemistry modification.

EPRI document TR-103515 "BWR Water Chemistry Guidelines" currently provides the basis for the methodology employed to maintain DWST and CST chemistry parameters within acceptable limits, ensure adequate sampling frequencies, and specify proper analysis techniques.

Demineralized water is supplied to both the DWST and CST via the Plant Hatch makeup demineralizer system. This system provides demineralized water to meet tank chemistry limitations through the use of filtration, ion exchange and degasification processes.

Control of demineralized water chemistry parameters, within the CST and DWST, is not maintained by any type of control system, such as ion exchange or filtration. Should demineralized water chemistry parameters exceed the limitations established by EPRI, appropriate corrective actions will be taken to minimize the potential for significantly increased corrosion rates and restore demineralized water purity.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

Portions of the following systems are directly or indirectly monitored by demineralized water chemistry control.

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

Note that while the demineralized water system proper (P21) is not within the scope of license renewal, several systems and components that receive makeup water from the DWST are within the scope of license renewal. Thus, DWST chemistry control is an important aspect of aging management for the systems listed above.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

Components exposed to a demineralized water environment are primarily fabricated from carbon steels, stainless steels, and aluminum alloys. Chemistry control is focused upon minimizing detrimental ionic species and conductivity. By controlling water chemistry in the CST and DWST, Plant Hatch reduces the potential for significant corrosion of plant systems and components exposed to a demineralized water environment.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

EPRI TR-103515 provides the basis for demineralized water chemistry parameters monitored to ensure adequate chemistry control at Plant Hatch. Demineralized water chemistry diagnostic parameters regularly monitored include conductivity, chloride and sulfate concentrations, total organic carbon, and silica content. Control of these parameters will reduce the potential for significant corrosion. In addition, DWST and CST conductivity and pH are diagnostically monitored.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

Demineralized water chemistry control is a mitigative activity and as such is not intended to directly detect age-related degradation of systems and components exposed to a demineralized water environment.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Demineralized water chemistry control does not directly monitor or trend age related degradation and as such is not credited to perform this attribute within the Hatch license renewal application. However, EPRI TR-103515 provides the basis for the methodology employed for periodic monitoring of demineralized water chemistry parameters at Plant Hatch. Chlorides, sulfates, total organic carbon, and silica are monitored weekly in accordance with EPRI TR-103515 recommendations. In addition, conductivity and pH are diagnostically monitored.

Acceptance Criteria

(Acceptance criteria are included.)

EPRI TR-103515 provides diagnostic parameters and associated limitations for DWST and CST chemistry analyses. The specific acceptance criteria included within EPRI TR-103515 are as follows:

Sulfates	< 10 ppb
Chlorides	< 10 ppb
Total Organic Carbon	< 200 ppb
Silica	< 100 ppb

In addition to the EPRI requirements shown above, pH and conductivity are diagnostically monitored.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

A review of plant deficiency cards submitted over the past 5 years showed that no age related deficiencies were noted due to significant corrosion of system components.

EPRI TR-103515 guidelines for auxiliary systems incorporate the input of industry experts and utility experience. Therefore, operation according to the guidelines specified by EPRI TR-103515 ensures that pertinent industry issues were considered.

Finally, CST and DWST chemistry excursions have been rare in the past. In the past five years, only minor excursions above the criteria specified within EPRI TR-103515 have occurred. None of these excursions were determined to be significant.

References

1. TR-103515, Electric Power Research Institute (EPRI), "BWR Water Chemistry Guidelines".

B.1.7 Suppression Pool Chemistry Control

Suppression pool chemical control is a mitigating activity designed to maintain structural integrity, reliability, and availability of plant systems and components by controlling fluid purity and composition.

The principal elements of suppression pool chemical control at Plant Hatch are regular sampling, results analysis and, when applicable, chemistry modification.

EPRI document TR-103515 "BWR Water Chemistry Guidelines" currently provides the basis for the methodology employed to maintain suppression pool chemistry parameters within acceptable limits, assure adequate sampling frequencies, and specify proper analysis techniques.

Control of suppression pool chemistry parameters is not maintained by any type of control system, such as ion exchange or filtration. Should suppression pool chemistry parameters exceed the limitations established by EPRI, appropriate corrective actions will be taken to minimize the potential for significantly increased corrosion rates and restore suppression pool purity.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

Portions of the following systems, structures and components are directly or indirectly monitored by suppression pool chemistry control:

B21 – Nuclear Boiler (SRV tailpipes and associated supports)
E11 – RHR
E21 – Core Spray
E41 – HPCI
E51 – RCIC
T23 – Primary Containment (including the torus)
T48 – Primary Containment Purge and Inerting

Also included are the suppression chamber vent headers, deflectors, internal supports, downcomers and braces, and interior platform supports.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

Components subjected to a suppression pool environment are primarily fabricated from carbon steels and stainless steels. Chemistry control is focused upon minimizing detrimental ionic species and conductivity. By controlling water chemistry in the suppression pool, Plant Hatch reduces the potential for significant corrosion of plant systems and components exposed to a suppression pool environment.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

EPRI TR-103515 provides the basis for suppression pool chemistry parameters monitored to ensure adequate chemistry control at Plant Hatch. Suppression pool chemistry diagnostic parameters regularly monitored include conductivity (zinc corrected), chloride and sulfate concentrations, and total organic carbon levels. Monitoring of these parameters will reduce the potential for significant corrosion.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

Suppression pool chemistry control is a mitigative activity and as such is not intended to directly detect age-related degradation of components exposed to a suppression pool environment.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Suppression pool chemistry control does not directly monitor or trend age related degradation and as such is not credited to perform this attribute within the Hatch license renewal application.

However, EPRI TR-103515 provides the basis for the methodology employed for trending, tracking, and regular evaluations of suppression pool water chemistry parameters at Plant Hatch. Sulfates, chlorides, zinc corrected conductivity, and total organic carbon are monitored quarterly in accordance with EPRI TR-103515 recommendations.

Acceptance Criteria

(Acceptance criteria are included.)

EPRI TR-103515 provides diagnostic parameters and associated limitations for suppression pool chemistry analyses. The specific acceptance criteria included within EPRI TR-103515 are as follows:

Sulfates	<200 ppb
Chlorides	<200 ppb
Conductivity	<5.0 µS/cm
Total organic carbon	<1000 ppb

In addition, zinc concentration is monitored quarterly since dissolution of the torus inorganic zinc coating can contribute to zinc content within the suppression pool and thereby contribute to pool conductivity.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

A review of plant deficiency cards submitted over the past 5 years showed that no age related deficiencies have been written on the structures or components within the scope of license renewal for which suppression pool chemical control is credited.

EPRI TR-103515 guidelines for auxiliary systems incorporate the input of industry experts and utility experience. Therefore, operation according to the guidelines specified by EPRI TR-103515 ensures that pertinent industry issues were considered.

Finally, suppression pool chemistry excursions have been rare in the past. In the past five years, only minor excursions above the criteria specified within EPRI TR-103515 have occurred. None of these excursions was determined to be significant.

References

1. *TR-103515, Electric Power Research Institute (EPRI), "BWR Water Chemistry Guidelines".*

B.1.8 Corrective Actions Program

SNC has established and implemented a QA Program for Plant Hatch that conforms to the criteria set forth in 10 CFR 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 Final Safety Analysis Report (FSAR), and outlined below. Corrective action and administrative control requirements apply to all components within the scope of license renewal.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

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 50, Appendix B, QA Program.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The Corrective Action Program provides a means to correct conditions identified as being adverse to quality. There are no preventive or mitigative attributes specifically credited for this program.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

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 Corrective Action Program provides a means to correct the identified condition.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

Detecting aging effects is not part of the Corrective Action Program. The Corrective Action Program provides a means to address the aging effects identified by other aging management activities.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

The corrective action process is monitored and trended to ensure that corrective actions taken are adequate and timely. Significant and non-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. In April 2000, Plant Hatch NS&C group began evaluating the effectiveness of the corrective action program against commonly used industry performance indicators.

Acceptance Criteria

(Acceptance criteria are included.)

The Corrective Action Program does not include specific acceptance criteria for in scope components. Generally, when the acceptance criteria of other aging management activities are not met, the Corrective Action Program provides a means to ensure appropriate corrective actions are taken.

Corrective Actions

(Corrective actions, including root cause determination and prevention of recurrence, should be timely.)

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 subsection 17.2.15 of the Unit 2 FSAR.

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.

Confirmation process

(Confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.)

As described in Unit 2 FSAR in subsection 17.2.15: Condition reports are reviewed to determine the regulatory reportability and significance by NS&C. Those items determined to be significant conditions adverse to quality (significant occurrence reports) are also reviewed by the Plant Review Board. Corrective actions taken for significant items are reviewed by NS&C supervision for assurance that appropriate action has been taken.

Administrative Controls

(Administrative controls should provide a formal review and approval process.)

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.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

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.

Review of the "Operating Experience" section for the other aging management programs described in Appendix B provides numerous examples of the Corrective Action Program being used to address and correct aging related conditions adverse to quality.

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

References

1. *Edwin I. Hatch Nuclear Plant Final Safety Analysis Report, Unit 2.*

B.1.9 Inservice Inspection 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. The ISI Program also includes augmented examinations required to satisfy commitments made by SNC (e.g., GL-88-01, NUREG-0619). The 10-year examination plan provides a systematic guide for performing nondestructive examinations of passive components in the scope of license renewal.

Plant Hatch has two units with different dates for construction permit and operating licenses. However, Unit 2's first 10-year interval was closed out early (1986) so Units 1 and 2 would be committed to the same version of Section XI. Accordingly, Plant Hatch is currently in the third 10-year interval. The period of extended operation will include the fifth and sixth inservice inspection intervals.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

The ISI Program contains examination requirements 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 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 – RHR and RHRSW
P41 – PSW
T23 – Primary Containment
T52 – Containment Penetrations

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The ISI Program is a condition monitoring program. As such, there are no preventive or mitigative attributes associated with this program.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

The ISI Program utilizes visual, surface and volumetric examinations to detect loss of material, cracking, and loss of preload.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

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 IWA-2210. The three types of visual examinations used are designated 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, erosion, 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 the associated supports such as verification of clearances, physical displacements, and loose or missing parts. This includes inspection for debris, corrosion, wear, erosion, or loss of integrity at bolted or welded connections.

Surface examinations are performed as defined in IWA-2220 to determine whether surface cracks or discontinuities exist. Acceptable examination methods include liquid penetrant and magnetic particle examinations.

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 RT or UT methods may be used.

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

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

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.

Acceptance Criteria

(Acceptance criteria are included.)

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 prior to 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 XI Code, 1992 Edition with 1992 Addenda.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

The Plant Hatch ISI Program is based upon the requirements of ASME Code. The ASME Code development process includes extensive review and approval of industry experts, thereby assuring that any significant industry data has been considered in 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 into10 CFR 50.55a provides additional assurance that all significant issues have been considered.

References

1. ASME Boiler and Pressure Vessel Code.

B.1.10 Overhead Crane And Refueling Platform Inspections

SNC identified the reactor building overhead crane and the refueling platform as active components for license renewal. However, SNC evaluated the passive structural elements of the crane and refueling platform in respect to their structural integrity. The aging management review for passive structural elements identified one aging effect, loss of material due to corrosion, as requiring management. Periodic visual inspections are conducted to monitor the condition of these components that are within the scope of license renewal.

The crane and refueling platform inspection program is an existing program that evaluates aspects of the crane and refueling platform that are broader than managing the single aging effect identified for license renewal. It also satisfies the requirements of the Unit 1 Technical Requirements Manual which requires surveillance testing of the 5-ton hoist, and the crane/hoist used for handling fuel assemblies or control rods. The original LRA Appendix A, Section A.1.10, described this entire program. This discussion will, when appropriate, acknowledge the instances where portions of the program not being credited for license renewal are included in Appendix A but will not elaborate on those aspects of the program.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

Certain long-lived passive elements in the following systems or structures are monitored for loss of material that might occur due to age related degradation:

F15 –Fuel and Control Rod Handling Equipment
T29 –Reactor Building, General
T31 –Refueling Floor Cranes and Hoists

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

There are no specific actions credited in the license renewal application as preventing or mitigating loss of material from passive load bearing components. Rather, these components are subjected to regular inspection as shown below.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

The contacting surfaces of the steel rails and the passive structural elements are periodically inspected in accordance with plant procedures. These inspections should continue to be adequate to detect loss of material from those surfaces during the extended period of operation.

Additional inspection activities not credited for license renewal aging management include a pre-operational static inspection, pre-operational dynamic inspection, operational inspection, maintenance inspection, and as required inspections. The overhead crane and refueling platform hoist, rigging, slings and lifting devices are visually inspected. A trial lift of the spent fuel pool gate or an equivalent weight is also performed for each device performing this lifting function. When cranes are in service, or prior to using standby cranes, detailed visual inspection of all wire rope is made to check for, among other things, general corrosion, kinks, and strand displacement. Hooks are visually inspected for cracks or distortion. Connections are checked for weld cracks and loose or missing bolts. Bridges, bridge rails, trolley and trolley rails are visually inspected for straightness and evidence of physical damage or cracking.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

General visual inspections are performed monthly. Visual inspections are performed annually. Further, overhead cranes are visually inspected daily when in use. In addition, although not credited for license renewal, annual magnetic particle tests are performed on hooks.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Plant procedures require that deficiencies discovered during the visual inspections be documented in accordance with the condition reporting process. The Plant Hatch corrective actions program trends significant deficiencies and ensures that proper corrective actions are accomplished.

Acceptance Criteria

(Acceptance criteria are included.)

<u>Credited For License Renewal Aging Management</u>

Bridges, bridge rails, trolley and trolley rails must be without evidence of physical damage due to loss of material.

<u>Not Credited For License Renewal Aging Management</u>

Bridges, bridge rails, trolley and trolley rails must be straight, and without evidence of physical damage such as cracking.

End connections must not be severely corroded, cracked, bent, worn or improperly applied. Wire rope must be within the maximum reduction from nominal as stated in plant procedures. Wire rope safety factors from ANSI B30.5 or SAE J959-1966 are applied to acceptance criteria. Any weld cracking requires performance of nondestructive testing. Loose bolts are replaced rather than tightened.

Plant Hatch overhead crane and refueling platform inspection procedures were developed using ANSI B30.2.0-1976 and NUREG-0612. Inspection procedures for fuel handling equipment were developed using ANSI B30.9-1971, ANSI/ASME B30.10-1982, ANSI N14.6-1978 and NUREG-0612.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

A review of plant deficiency cards submitted over the past 5 years did not reveal any instances of age related loss of material from the in-scope elements of the overhead crane or the refueling platform. Operating experience for the reactor building overhead cranes and refueling platform indicates that annual preventive maintenance and inspections, visual inspections required prior to use, and required testing have maintained the cranes in acceptable operating condition.

References

1. *Edwin I. Hatch Nuclear Plant, Unit 2 Final Safety Analysis Report*

B.1.11 Torque Activities

Torque activities 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.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

Torque activities are applicable to bolts, studs, nuts, and washers within systems in the scope of license renewal.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

Proper torque techniques minimize the potential for improper preload within bolted connections, thereby minimizing the potential for mechanical joint leakage. Plant Hatch Torque Activities use the techniques described below to obtain proper preload.

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 may be 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 based on the judgment of the responsible supervision, leveling passes may be repeated at the final torque value after 24 hours.

The amount of preload prescribed by the Torque Activities includes a component that accounts for loss of preload due to a number of factors including:

- vibration
- gasket compression
- elastic interaction
- settlement of contact surfaces
- large cyclic load (near yield strength)
- high thermal temperatures
- self-loosening

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

Torque activities are not intended to directly monitor bolting parameters on an ongoing basis. The mitigative actions performed by this activity are sufficient such that this attribute is not required.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

Torque activities are not intended to directly detect loss of preload within mechanical joints. The mitigative actions performed by this activity are sufficient such that this attribute is not required.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Torque activities are not intended to trend loss of preload within mechanical joints. The mitigative actions performed by this activity are sufficient such that this attribute is not required. Torque activities are considered a one time activity.

Acceptance Criteria

(Acceptance criteria are included.)

Plant Hatch torque activities are based on the guidance of EPRI NP-5769 "Degradation and Failure of Bolting in Nuclear Power Plants," Vol. 1 and 2. This EPRI document has been generally endorsed by the NRC in NUREG 1339.

Other codes and standards considered during development of the Plant Hatch torquing procedure were: ASME, Section VIII, Div. 1, App. 2; ASME, Section II, Specification for Carbon Steel Externally Threaded Standard Fasteners; ASTM Standards, Section 15, Volume 15.08, Fasteners; and ASME B31.1.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

A review of plant deficiency cards submitted over the past five years shows that instances of mechanical joint leakage have been noted during inspections, system walkdowns, and regular system surveillance activities. In each case, the Plant Hatch corrective actions program was utilized to repair the leak with no loss of intended function.

References

1. *ASME Boiler and Pressure Vessel Code.*

2. *EPRI NP-5769 "Degradation and Failure of Bolting in Nuclear Power Plants," Vols. 1 and 2, Project 2520-7, 1988.*

3. *NUREG 1339 "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," 1990.*

4. *ASME, Section II, Specification for Carbon Steel Externally Threaded Standard Fasteners.*

5. *ASTM Standards, Section 15, Volume 15.08, Fasteners*

6. *ASME B31.1 "Power Piping"*

B.1.12 Component Cyclic Or Transient Limit Program

The Plant Hatch CCTLP is a surveillance program required by Technical Specifications. It is a monitoring program designed to track cyclic and transient occurrences to ensure that reactor coolant pressure boundary components and the torus will remain within the ASME Code Section III fatigue limits, including the effects of a reactor water environment. Currently, only monitoring of the limiting locations for the RPV is required, although monitoring of the torus and Class 1 piping has been implemented.

Plant cycles and transients that significantly contribute to fatigue usage of Class 1 components have been identified. At least once per operating cycle, each unit's operating records are reviewed to determine the number of design transients that have occurred since the last time CUF was calculated. Applying the actual cycles that have occurred to the formulas that represent design severity of cycles results in sufficient conservatism, including effects due to environmental factors, that cracking due to thermal fatigue is not expected as long as the CUF is less than 1.0.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

The scope includes the RPV, the torus and all Class 1 piping. The Unit 1 FSAR, Section 4.25 and the Unit 2 FSAR, Section 5.4.6.4 document the bounding RPV locations monitored. A fatigue evaluation of the torus established the critical locations of the torus for monitoring. All Class 1 calculations for Plant Hatch piping were screened. Those calculations showing a CUF greater than 0.1 were selected for fatigue monitoring. For each design stress calculation selected, the limiting location was determined, and a CUF monitoring formula was developed.

The monitoring formulas account for any effects due to power uprate or extended power uprate and contain sufficient conservatism to account for environmental effects of reactor water when applicable. Therefore, the bounding locations for the reactor pressure vessel, torus, and all Class 1 piping significantly susceptible to fatigue are monitored.

The scope of the CCTLP includes long-lived passive components in the following systems or structures:

B11 – Reactor Pressure Vessel
B21 – Nuclear Boiler
B31 – Reactor Recirculation
T23 -- Primary Containment
T52 – Containment Penetrations

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

This program does not specifically prevent or mitigate cracking in the components monitored and, therefore, is not credited for prevention or mitigation. Rather, bounding fatigue calculations for the limiting components are regularly updated based upon monitoring specific transients that have occurred since the last calculation was performed.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

Plant transients were evaluated to determine what events should be considered for fatigue calculations. Plant transients that significantly contribute to fatigue usage are counted. The plant fatigue CUF is calculated for four limiting high stress RPV boundary components on each unit. The RPV main closure studs, the RPV shell, the RPV recirculation inlet nozzles, and the RPV feedwater nozzles have been shown by analysis to be the limiting components.

CUF is also calculated for the limiting location for the torus on each unit, and for eight locations within the Class 1 boundary. Class 1 monitoring includes the limiting locations on the reactor vessel equalizer piping, the core spray piping, the standby liquid control piping, the feedwater, HPCI, RCIC, and RWCU piping, and the main steam piping for Unit 1. On Unit 2, the monitored piping is the limiting locations for the feedwater piping, the primary steam condensate drainage, and the main steam piping.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

This program does not actually detect the aging effect. Instead, it counts events that contribute to the aging effect and calculates a CUF value. Because of conservatisms in the calculations, a CUF of 1.0 or higher does not indicate that components have fatigue cracks. However, cracking due to thermal fatigue is not expected to occur as long as the CUF can be shown to be less than 1.0.

The CUF for each of the limiting components on each unit is calculated at least once per operating cycle. Data may be collected at any time during the surveillance period.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

The surveillance is performed at least once per operating cycle. To project the 60-year CUF, the transients that occurred in recent years are averaged and multiplied by the remaining years (assuming a 60-year life). Transients that did not occur in recent years are assumed to occur once during the remaining plant life. If the 60-year CUF is projected to exceed 1.0, a condition report is initiated to determine and take appropriate corrective action. This action would include an engineering evaluation determining how long the plant can continue to operate without the CUF exceeding 1.0. Additional actions could include but are not limited to the following:

- 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 revise 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.

Acceptance Criteria

(Acceptance criteria are included.)

High fatigue usage components have been selected to be tracked by this program to assure that the plant will continue to meet the ASME Code, Section III, and CUF design requirement value of less than 1.0.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

Originally, Plant Hatch calculated CUF using the design cycle numbers from the respective FSARs. After a number of years, the Unit 2 feedwater nozzles failed to meet the ASME Code, Section III design requirement value of less than 1.0 when calculated using the design cycle method.

Subsequently, Plant Hatch revised the monitoring program to adopt the more practical cycle counting method currently used. This method has been explicitly approved by the NRC. Additional monitoring points have been added.

Currently, no monitored locations are projected to exceed a CUF of 1.0 during 60 years of plant operation.

References

1. Edwin I. Hatch Nuclear Plant, Units 1 and 2 Final Safety Analysis Report.

2. Edwin I. Hatch Nuclear Plant Technical Specifications, Units 1 and 2.

B.1.13 Plant Service Water And RHR Service Water Inspection Program

The PSW and RHRSW passive components could potentially be adversely affected by aging mechanisms, such that loss of material, flow blockage, and cracking (of RHR heat exchanger tubes) could occur during the extended period of operation. This program is designed to detect wall thickness degradation, fouling or cracking in the PSW and RHRSW systems. The specific inspection locations in the PSW and RHRSW systems are based on a representative sample of the most susceptible locations. Locations determined to be prone to corrosion are infrequently used piping (stagnation water), submerged piping, piping with low fluid velocity, small diameter piping, backing rings, socket welds, and heat affected zone of a weld. Locations prone to clogging include those prone to corrosion, horizontal runs of piping at the bottom of vertical runs, intermittently used piping, and low point drains. Locations prone to cracking include locations susceptible to vibration fatigue and stress corrosion cracking (RHR heat exchanger tubes). Locations prone to erosion include the areas with high velocity.

This program partially satisfies the requirements of Nuclear Regulatory Commission Generic Letter 89-13, July 18, 1989. In addition, other industry standards and codes are used as guidance.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

The PSW and RHRSW inspection program will inspect portions of the following systems that are within the scope of license renewal:

E11 – RHR and RHRSW
P41 – PSW
W33 - Travelling Water Screens

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The PSW and RHRSW piping inspection program requires that the intake structure pump suction pit will be visually inspected every twelve months by divers. Any accumulations of biological fouling organisms, sediment, and corrosion products found during the inspection will be removed to prevent these foreign materials from entering the system.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

The PSW and RHRSW piping inspection program provides for visual and volumetric examinations intended to detect wall thinning, surface indications, and reduction of flow area within service water system components. This program also provides hardness testing to detect selective leaching.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner)

PSW and RHRSW piping inspection program examinations to detect wall thickness degradation include volumetric examinations (radiographic and ultrasonic), and visual examinations (including use of depth gages). Volumetric examinations, visual inspections, and flow testing are utilized to detect reduction of flow area. At least one Brinell hardness or Rockwell test will be performed on one brass and gray cast iron component of the PSW or RHRSW system assuming such components exist within the system at the time of the test. Some inspections of the submerged portions of the piping at the intake structure will be performed by divers.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Except for the heat exchangers, which are inspected visually only, the inspection frequencies are determined by the trends in wall thickness reduction or flow area reduction. If the trend indicates that the wall thickness or flow area might be reduced to the minimum allowable value, then the inspection frequency and lot size are adjusted in accordance with the trend. ASTM E122-89, “Standard Practice For Choice Of Sample Size To Estimate A Measure Of Quality For A Lot Or Process” is used to establish the sample size. In all cases the determination of the inspection frequency will allow at least one full operating cycle to complete repairs or replacements prior to reaching the minimum allowable wall thickness value.

For heat exchanger components the visual inspection frequency is every three cycles but may be revised based on observed trends.

If hardness testing yields unfavorable results, the scope will be expanded to other components and systems based on engineering evaluation. Otherwise, this shall be a one-time test.

Acceptance Criteria

(Acceptance criteria are included.)

Minimum wall thickness is calculated in accordance with the piping design code, piping stress requirements and the piping specification drawings. The bases for the acceptance criteria are contained in the PSW and RHRSW Inspection Program procedures. Measured wall thickness values shall not fall below these acceptable values.

Acceptance criteria for visually identified surface cracking are based on engineering evaluation and, if necessary, proper corrective actions are implemented in accordance with the Plant Hatch corrective actions program.

For flow rate testing, acceptance flow rates are based upon functional performance requirements for the component under normal and accident conditions.

Acceptance criteria for hardness testing are based on the component material specifications (ASME, ASTM, etc.).

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

It is likely that NRC Generic Letter 89-13 prompted an increased awareness toward raw water system problems and the concomitant decrease in the occurrence of those problems throughout the industry since about 1991. However, except for the obvious trend, the industry data itself is not extremely helpful in the aging management demonstration because of possible misdiagnoses, incomplete failure descriptions, and the potential for lack of conformity among the plants in reporting data.

Over the past 4 to 5 years, Plant Hatch has experienced some aging related problems in PSW and RHRSW components. These include loss of material, cracking, and loss of heat exchanger performance. Deficiencies are corrected in accordance with the Plant Hatch corrective actions program.

Based on years of experience, significant program improvements have been made in the PSW and RHRSW inspection program. For example, inspection frequencies have been increased and additional non-destructive examinations have been performed, as more data became available. In some cases, improved materials have been used to replace failed or failing piping. For example, whenever possible, small-bore carbon steel piping is replaced with 304 stainless. To date, there have been no corrosion failures in this small-bore stainless steel piping.

References

1. *NRC Generic Letter 89-13, Service Water System Problems Affecting Safety Related Equipment, July 18, 1989.*

2. *HL-882, Georgia Power Company Response to Generic Letter 89-13, January 23, 1990.*

3. *NUREG-1275, Volume 3, Operating Experience Feedback Report – Service Water System Failures and Degradations.*

4. *Edwin I. Hatch Nuclear Plant Units 1 and 2, Generic Letter 89-13 Initial Actions Summary Report, May 1992.*

5. *SAND93-7070 "Aging Management Guideline for Commercial Nuclear Power Plants – Heat Exchangers."*

6. *ASME Boiler and Pressure Vessel Code, Code Case N-480 "Examination Requirements for Pipe Wall Thinning due to Single Phase Erosion and Corrosion, Section XI, Division 1."*

B.1.14 Primary Containment Leakage Rate Testing Program

The Plant Hatch Primary Containment Leakage Rate Testing Program is a condition and performance monitoring program that ensures the structural integrity of primary containment through visual inspection and performance testing activities. Plant Hatch Technical Specifications require the implementation of the Primary Containment Leakage Rate Testing Program and the attendant written procedures.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

This program applies to all 10 CFR 50 Appendix J, Option B leakage rate testing requirements for systems, structures, and components within the scope of license renewal. This includes the steel primary containment, containment penetrations, and containment internal structures that perform a pressure retaining function. All of these components are found within the Primary Containment (T23) and Drywell Penetrations (T52) systems. The program was developed through the use of 10CFR50, Appendix J, Option B, Regulatory Guide 1.163, NEI 94-01, and ANSI/ANS 56.8-1994.

The program describes the implementation and documentation requirements for the performance of leakage rate tests, including frequency of testing and leakage acceptance criteria based on requirements and guidance established in the documents referenced above and NRC approved exemptions.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The Primary Containment Leakage Rate Testing Program is a condition and performance monitoring program. No preventive or mitigative actions are associated with this program.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

A general visual inspection of the accessible interior and exterior surfaces of the drywell and torus are performed prior to conducting a Type A (ILRT) test.

Criteria are defined for establishing Type A, Type B, and Type C test frequencies and administrative leakage limits based on performance. Type A tests (ILRT) 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

Specifications amendments and exemptions. No exceptions are taken to regulatory positions C.1 through C.4 of RG 1.163.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

The containment leakage rate testing program utilizes pressure tests of containment to verify that primary containment pressure integrity remains intact. In addition, general visual inspections are conducted prior to performing a type A (ILRT) test.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Type A, B, and C pressure testing is performed periodically. Test frequencies may be reduced based on previous results. Visual inspections are performed based on test results and as warranted based on pressure test frequency. The Plant Hatch corrective actions program provides for trending of deficiencies resulting from primary containment leakage rate testing.

Acceptance Criteria

(Acceptance criteria are included.)

The Primary Containment Leakage Rate Testing Program is based upon Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," September 1995. ANSI/ANS-56.8-1994, "American National Standard for Containment System Leakage Testing Requirements, 1994," and NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J", July 26, 1995 are also used.

The primary containment leakage rate acceptance criteria and the air lock testing acceptance criteria for the Plant Hatch Primary Containment Leakage Rate Testing Program are specified in Section 5.5 of the Technical Specifications.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

A review of plant deficiency cards submitted over the past five years showed that several minor age related deficiencies relating to sealant degradation and associated metal corrosion had been written on the T23 and T52 systems. Several containment penetrations were replaced on Unit 1 due to excessive leakage detected during local leakage rate testing. The leakage cause was identified as maintenance related and not due to age related degradation. These deficiencies were corrected in accordance with the Plant Hatch corrective actions program.

References

1. *Edwin I. Hatch Nuclear Plant Technical Specifications, Units 1 and 2.*

B.1.15 Boiling Water Reactor Vessel And Internals Program

The BWRVIP is an association of utilities formed to focus on resolution of BWR vessel and internals issues. The BWRVIP Program was developed based on over 20 years of service and inspection experience and is focused on detecting evidence of component degradation well in advance of significant degradation.

The BWRVIP developed inspection and evaluation reports for internals components and submitted them to the NRC for review and approval. These inspection and evaluation reports address both the current term and license renewal. With regard to license renewal, the inspection and evaluation reports specifically addressed the internals relative to the requirements of the 10 CFR 54 regulations. The NRC is currently completing its review of the reports and issuing SERs to address the renewal term. These SERs establish the adequacy of the internals for renewal by concluding the rule provisions have been satisfied including the identification and assessment of aging effects, the evaluation of the adequacy of those programs with regard to those aging effects, and demonstration that these programs will assure the functionality of internals into the renewal term.

SNC has evaluated the BWRVIP Program for its applicability to the Hatch Units 1 and 2 design, construction, and operating experience. The RPV internals, including the materials of construction, are addressed by the BWRVIP Program inspection and evaluation documents. The plant operation parameters, including temperature, pressure and water chemistry, are consistent with those used for the development of the inspection and evaluation documents. SNC has determined the following:

The components, which require aging management review in accordance with the Rule, are covered by the BWRVIP Program reports. The BWRVIP Program reports cover all Hatch internals design.

Therefore, SNC has established that the BWRVIP Program reports bound the Hatch Units 1 and 2 design and operation.

Additionally, the BWRVIP Program for reactor assembly components subject to license renewal as implemented at Plant Hatch employs the BWRVIP Program criteria documented in the final NRC SERs, except where specific exception has been identified to the NRC.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

Reactor vessel internals requiring aging management within the scope of the 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 LRA, only the Unit 1 top guide is included. Subsequent to submitting the LRA SNC has determined that due to extended power uprate the unit 2 top guide must also be included.

All of the above listed components are included as part of the Reactor Assembly (B11).

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

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 in early stages such that proper evaluations and corrective actions may 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.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

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 such 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.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

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 inspection and evaluation document, unless specific exception is identified to the NRC.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Monitoring of the detrimental effects of aging within reactor assembly components are specified within BWRVIP inspection and evaluation documents. The frequency of examination specified within applicable BWRVIP inspection and evaluation documents varies for each component or subassembly. The frequency is based 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.

Acceptance Criteria

(Acceptance criteria are included.)

BWRVIP inspection and evaluation documents provide the basis for Plant Hatch reactor vessel internals inspection requirements, acceptance criteria, and proper corrective actions. SNC has incorporated these applicable inspection and evaluation documents into the Hatch license renewal application by specific reference. BWRVIP inspection and evaluation documents applicable to Plant Hatch reactor assembly components are as follows:

Reactor Assembly BWRVIP Document Applicability

Component	Reference
shroud (including repair hardware)	BWRVIP-76
shroud support	BWRVIP-38
core spray piping and sparger	BWRVIP-18
top guide	BWRVIP-26
control rod guide tube	BWRVIP-47

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

The operating experience for the 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 nonsafety-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. SNC conservatively decided to install 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.

References

1. *(BWRVIP-38), "BWR Shroud Support Inspection and Flaw Evaluation Guidelines," EPRI TR-108823, September 1997.*

2. *(BWRVIP-41), "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines," EPRI TR-108728, October 1997.*

3. *(BWRVIP-76), "BWR Core Shroud Inspection and Flaw Evaluation Guidelines," EPRI TR114232, November 1999.*

4. *(BWRVIP-18), "BWR Core Spray Internals and Flaw Evaluation Guidelines," EPRI TR-106740, July 1996.*

5. *(BWRVIP-26), "BWR Top Guide Inspection and Flaw Evaluation Guidelines," EPRI TR-107285, December 1996.*

6. *(BWRVIP-47), "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," EPRI TR-108727, December 1997.*

B.1.16 Wetted Cable Activities

Several 4 kV power cables and transformer feeder cables within the scope of license renewal run through conduits that junction in below grade pull boxes located outside. These cables might become immersed in rainwater if left unattended. In turn, wetted cable insulation might result in loss of insulation resistance.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

Wetted cable activities pertain to certain insulated cable, outside containment, in portions of the following systems:

E11 – RHR and RHRSW
E21 – Core Spray
P41 – PSW

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

By routinely monitoring for water in the applicable pull boxes, and draining accumulated water when necessary, Plant Hatch prevents or mitigates adverse changes in cable insulation resistance that might otherwise occur if cables were left immersed.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

Megger testing cables measures cable insulation resistance. A reduction in cable insulation resistance indicates aging degradation. Pull boxes are drained quarterly, which mitigates insulation degradation due to moisture intrusion.

E11 RHR and RHRSW motors and cable are megger tested every 18 months.
E21 Core Spray motors and cable are megger tested every 18 months.
P41 PSW motors and cables are megger tested every 12 months.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

Pull box water level monitoring is not intended to directly detect loss of insulation resistance. Periodic megger and PI testing is the method by which actual power cable insulation degradation would be detected, regardless of whether or not the degradation was attributable to immersion.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Although procedures require pull box water levels to be recorded, and require accumulated water to be pumped out, these activities do not directly monitor or trend degradation in cable insulation resistance. Loss of insulation resistance in a power cable would be detected as a function of megger and PI testing.

The current water level surveillance frequency has proven to be adequate. However, this frequency may be adjusted due to significant events such as inordinate amounts of rainfall, etc.

Plant procedures require that deficiencies discovered during the performance of the program activities be documented in accordance with the Plant Hatch corrective actions program.

Acceptance Criteria

(Acceptance criteria are included.)

Pull boxes found to contain water are required by procedure to be drained to 1 inch of water or less.

Existing cables and loads must successfully pass megger and PI testing. Leakage current for tested cables cannot be over 250 microamps (all voltages) and individual readings on each phase must be within 200% of each other. If the pull boxes contain water at the time of inspection, the water will be drained.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

A review of plant deficiency cards submitted over the past five years found no age-related deficiencies related to the subject cables.

References

1. *Edwin I. Hatch Nuclear Plant, Unit 2 Final Safety Analysis Report*

B.1.17 Reactor Pressure Vessel Monitoring Program

The RPV Monitoring Program is a condition monitoring and surveillance program at Plant Hatch. It is based on detailed evaluation of the Plant Hatch Unit 1 and Unit 2 RPVs. The program is supported by several industry topical reports developed through the BWRVIP, the principal one being BWRVIP-74, which is under review by the NRC at the time of the license renewal application.

The BWRVIP developed inspection and evaluation reports for RPV components and submitted them to the NRC for review and approval. These inspection and evaluation reports address both the current term and license renewal. With regard to license renewal, the inspection and evaluation reports specifically addressed RPV components relative to the requirements of the 10 CFR 54 regulations. The NRC is currently completing its review of the reports and issuing SERs to address the renewal term. These SERs establish the adequacy of RPV components for renewal by concluding the rule provisions have been satisfied. The provisions include the identification and assessment of aging effects, the evaluation of the adequacy of those programs with regard to those aging effects, and demonstration that these programs will assure the functionality of internals into the renewal term.

SNC has evaluated the BWRVIP Program for its applicability to the Hatch Units 1 and 2 design, construction, and operating experience. The RPV components, including the materials of construction, are addressed by the BWRVIP Program inspection and evaluation documents. The plant operation parameters, including temperature, pressure and water chemistry, are consistent with those used for the development of the inspection and evaluation documents. SNC has determined the following:

- The components, which require aging management review in accordance with the Rule, are covered by the BWRVIP reports.
- The BWRVIP Program reports cover all Hatch RPV component designs.

Therefore, SNC has established that the BWRVIP reports bound the Hatch Units 1 and 2 design and operation.

Additionally, the BWRVIP Program for reactor assembly components subject to license renewal as implemented at Plant Hatch employs the BWRVIP Program criteria documented in the final NRC SERs, except where specific exception has been identified to the NRC.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

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 the closure studs, the attachment welds for internal core spray pipe, jet pump riser brace pad, and shroud support are also included.

All of the above listed components are included as part of the Reactor Assembly (B11).

Preventive or Mitigative Actions
(Preventive actions to mitigate or prevent aging degradation.)

The RPV Monitoring Program is a condition monitoring and surveillance program which utilizes enhanced visual, surface, and volumetric examinations; pressure testing; and materials testing to detect cracking due to corrosion and fatigue, and loss of fracture toughness due to neutron embrittlement of beltline materials. Early detection and subsequent evaluation and corrective actions are considered adequate to mitigate degradation of reactor assembly components before component function is adversely affected.

Parameters Inspected or Monitored
(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

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 such 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.

In addition, RPV components are inspected for cracking and loss of fracture toughness in accordance with BWRVIP-74, Section XI of the ASME Code, and 10 CFR 50 Appendices G and H.

Detection of Aging Effects
(The method of detection of the aging effects is described and performed in a timely manner).

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.

RPV nozzles and safe ends are examined as required by ASME Section XI or an augmented program (NUREG-0619), in accordance with the Plant Hatch ISI Program. This includes ultrasonic and surface examinations for nozzles 4 NPS and larger, and surface examinations for nozzles less than 4 NPS. Pressure tests for the Class 1 boundary are performed at the conclusion of each refueling outage in accordance with ASME Section XI.

The recirculation inlet nozzles and the feedwater nozzles are covered by the component cyclic and transient limit program described elsewhere.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Monitoring of the detrimental effects of aging within reactor assembly components is specified within BWRVIP inspection and evaluation documents, ASME Section XI, and 10 CFR 50 Appendices G and H. The Plant Hatch corrective actions program provides for trending of significant indications noted during BWRVIP inspections.

Acceptance Criteria

(Acceptance criteria are included.)

RPV ultrasonic examinations and the pressure tests with the associated visual examinations will be conducted in accordance with ASME Section XI as part of the ISI Program that is required by 10 CFR 50.55a. RPV surveillance capsule testing is required by 10 CFR 50 Appendix H. That testing provides data used to show that the criteria for fracture toughness of 10 CFR 50 Appendix G are satisfied.

Limits are imposed on pressure and temperature by 10 CFR 50 Appendix G. Pressure-Temperature limit curves have been prepared for Hatch Units 1 and 2 to allow operation up to 54 EFPY.

Appendix G of 10 CFR 50 also contains requirements for USE to ensure adequate fracture toughness is maintained. USE calculations performed for Plant Hatch limiting beltline materials, using equivalent margins analysis, justify operation up to 54 EFPY. Feedwater nozzles will be examined in accordance with ASME Section XI and the Plant Hatch implementation of NUREG-0619.

BWRVIP inspection and evaluation documents provide a basis for Plant Hatch reactor vessel inspection requirements, acceptance criteria, and proper corrective actions. SNC has incorporated these applicable inspection and evaluation documents into the Hatch license renewal application by specific reference. BWRVIP inspection and evaluation documents applicable to Plant Hatch reactor vessel components are as follows:

Reactor Assembly BWRVIP Document Applicability

Component	Reference
RPV shell and heads	BWRVIP-74
Nozzles (including safe ends and thermal sleeves)	BWRVIP-74
Appurtenances	BWRVIP-74
Penetrations	BWRVIP-27
Attachments and connecting welds Shroud support weld Jet pump pad weld Closure studs and support skirt	BWRVIP-38 BWRVIP-41 BWRVIP-48 BWRVIP-74

The requirements of ASME Section XI apply to attachments welded to the RPV, welded core support structures, and penetrations.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

A review of the operating experience for both Hatch reactor pressure vessels 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 age-related issues for the reactor vessel. There was one instrument penetration that developed a leak attributed to 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.

References

1. *(BWRVIP-74), "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," Electric Power Research Institute (EPRI) TR-113596, September 1999.*

2. *(BWRVIP-27), "BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines," EPRI TR-107286, April 1997.*

3. *(BWRVIP-38), "BWR Shroud Support Inspection and Flaw Evaluation Guidelines," EPRI TR-108823, September 1997.*

4. *(BWRVIP-41), "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines," EPRI TR-108728, October 1997.*

5. *(BWRVIP-48), "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines," EPRI TR-108724, February 1998.*

6. *ASME Boiler and Pressure Vessel Code.*

B.2 ENHANCED PROGRAMS AND ACTIVITIES

B.2.1 Fire Protection Activities

Fire protection activities are comprised of inspections, condition monitoring and performance monitoring activities. Fire protection activities provide assurance that a fire will not prevent the performance of necessary safe shutdown functions. Through a defense-in-depth philosophy, the Fire Protection Program is designed to minimize both the probability and consequences of postulated fires.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

The portion of the Plant Hatch fire protection activities credited for license renewal is that portion included in Appendix B of the Fire Hazards Analysis (FHA). It includes passive long-lived components in water based and gaseous fire suppression systems, the fire pump diesel fuel oil supply system (tanks and piping), fire doors, fire penetration seals, and cable tray enclosures. All of these components are part of the fire protection (X43) system.

Current fire protection activities will be enhanced to include periodic inspection of water suppression system strainers and a one-time sprinkler head inspection. These enhancements will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The fire protection activities are comprised of inspections, condition monitoring and performance monitoring activities. There are no preventive or mitigate attributes associated with the condition and performance monitoring elements of this program.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

Surveillance and inspection of fire protection systems and components are performed in accordance with Appendix B of the FHA.

For water based fire protection systems, the fire protection activities include the following tests and inspections. Flushing of loop headers is performed every 18 months to remove corrosion product buildup and ensure adequate flow through the system. Flow testing of water based fire suppression mains is performed every 3 years and system frictional pressure drop is measured. Fire Water Tank external surfaces are inspected annually and external and internal surfaces are inspected every 5 years for corrosion and general condition of the protective coating. Sizes and depth of pits are recorded and interior surfaces are cleaned as required to facilitate inspection. The contained water supply volume in these tanks is confirmed at least once per 31 days. Each fire pump is started once per 31 days and run for at least 30 minutes. Each diesel driven pump is started at least once per 18 months during shutdown and run for at least 60 minutes. The capacity and developed head of each fire pump is confirmed at least once per 12 months. Sprinkler heads and nozzles are visually inspected for degradation every 18 months and open head / deluge spray nozzles are air flow tested every 3 years. A sprinkler system header flow activity is conducted quarterly to verify unobstructed flow. A sprinkler system trip test is conducted every 6 months to verify operability. Hose stations are inspected every 31 days and hose station valves are partially opened to demonstrate unobstructed flow every 2 years. Water suppression system strainer internals are inspected every 2 years. In-scope fire hydrants are flow checked at least once every 12 months. Each testable isolation valve in the water suppression system flow path is cycled every 12 months and each valve that is not testable during plant operation is cycled every 18 months. All in-scope, above ground piping and equipment coatings or paint are inspected per the industry guidance of the Protective Coatings Program.

For the fire protection pump diesel fuel oil supply system, the fire protection activities include the following tests and inspections. Each fire diesel fuel oil storage tank level is confirmed at least once per 31 days. The fuel oil system is inspected for leaks at least once per 31 days. Each fuel oil storage tank is sampled for water, sediment, and other contaminants on a quarterly basis. The fuel oil storage tanks are drained and inspected for corrosion, based on sampling and as deemed necessary by Plant Maintenance Engineering. Each fire diesel is started and operated at least once per 31 days and at least once per 18 months during shutdown to demonstrate, among other things, operability of fuel oil supply system. All in-scope, above ground piping and equipment coatings or paint are inspected per the industry guidance reflected in the Protective Coatings Program.

For compressed gas based fire suppression systems, the fire protection activities include the following tests and inspections. All CO_2 system components are visually inspected once every 62 days and performance tested annually. The periodic visual inspections include CO_2 storage tank pressure and level, tank insulation condition, and pressure boundary leaks. The annual performance test includes the discharge of a small volume of CO_2 through system nozzles within a specified time period. All in-scope, above ground CO_2 piping and equipment coatings or paint are inspected per the industry guidance of the Protective Coatings Program.

For fire penetration seals, the fire protection activities include the following inspections. A 10% sample of each type of penetration seal is visually inspected at least once every 18 months and samples are selected such that each penetration seal is inspected at least once every 15 years.

For cable tray enclosures, the fire protection activities include the following inspections. In-scope cable tray enclosures are visually inspected once every 18 months.

For fire doors, the fire protection activities include the following tests and inspections. In-scope fire doors are visually inspected once every 6 months and functionally tested once per 18 months. Exterior coatings or paint are inspected per the industry guidance reflected in the Protective Coatings Program.

A one-time inspection called "Sprinkler Head Inspections" will be performed at or before the start of the extended period of operation for closed sprinkler heads in the scope of license renewal. A random sampling of each type of sprinkler head in the scope of license renewal will be submitted to a recognized laboratory for testing. Based on the results, corrective actions would be accomplished, if required, to assure continued sprinkler head functionality during the period of extended operation.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

Detection of flow blockage, loss of material, cracking, and changes in material properties are accomplished directly by visual examinations of component surfaces and indirectly through the use of flow or functional testing.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Results of fire protection system tests and inspections are documented in accordance with Plant Hatch procedural requirements. The Plant Hatch corrective actions program is utilized to monitor and trend fire protection system deficiencies and to implement timely corrective actions.

Acceptance Criteria

(Acceptance criteria are included.)

Any significant degradation of fire protection system components observed during visual inspections or performance testing activities are noted and corrective actions implemented in accordance with the Plant Hatch corrective actions program. Acceptance criteria are specifically stated in the plant procedures that govern each test or inspection.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

Based on a review of five years of plant deficiency card data, deficiencies in water based fire suppression systems include deterioration of coatings within the fire water storage tank and fouling of lines due to corrosion product buildup. These deficiencies were identified during testing and inspection required by the Fire Protection Activities or during normal walkdowns. Due to the design features of the system, including excess capacity and loop design, none of these failures was judged to constitute a loss of intended function.

A similar plant deficiency card review for other fire protection system components, identified deficiencies concerning minor degradation of fire penetration seals and exterior corrosion on gaseous fire suppression system piping. None of these deficiencies were determined to be significant since no loss of intended function occurred.

References

1. *Edwin I. Hatch Nuclear Plant, Units 1 and 2 Fire Hazards Analysis and Fire Protection Program.*

B.2.2 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. FAC is different from many other corrosion processes in that corrosion rates may be generally predicted.

The basis for the Plant Hatch FAC program is EPRI NSAC-202L "Recommendations for an Effective Flow-Accelerated Corrosion Program" and the associated CHECWORKS™ computer code which is used to create a Plant Hatch predictive CHECWORKS™ FAC model. This plant predictive FAC model accounts for system conditions relevant to FAC such as pH, dissolved oxygen content, fluid (steam) quality, temperature, pipeline velocity, component geometry, and material of construction.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

Portions of the following systems are included within the scope of the FAC program:

B21 – Nuclear Boiler
E41 – HPCI
E51 – RCIC
N61 – Main Condenser

Portions of these systems are modeled by the plant predictive FAC model and are periodically examined based on the recommendations of the EPRI NSAC-202L since they meet all of the screening criteria contained within EPRI NSAC 202L for systems potentially susceptible to FAC.

The FAC program will be enhanced to include some of the in scope components in the systems listed above that do not meet all of the FAC criteria, within EPRI NSAC 202L, and that are excluded from the plant predictive FAC model. These components will be inspected in accordance with FAC program requirements. This enhancement will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The FAC program is a condition monitoring program that utilizes ultrasonic, radiographic, and visual inspections to identify aging effects prior to any loss of intended function. As such, there are no preventive or mitigative attributes associated with this program.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

The primary parameter monitored by the FAC program is component wall thickness.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

FAC program inspection techniques are based on the recommendations of EPRI NSAC-202L. UT by qualified and certified inspection personnel is utilized to detect wall thinning. RT is permissible in cases where UT is impractical, such as small-diameter piping. In certain cases visual examinations of the piping inside diameter may be performed with follow-up UT contingent upon the visual examination results.

Additionally, the plant predictive FAC model predicts wear rates in FAC susceptible piping systems, thereby providing an estimate of possible aging effects within FAC susceptible systems.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

The CHECWORKS™ program contains a database that maintains inspection data for in-scope components and adjusts wear predictions for affected lines using this inspection data. Inspection results and information obtained from the plant predictive FAC model are also used to estimate future monitoring requirements.

Inspection data related to components not included within the plant predictive FAC model is documented by procedure and utilized to estimate future inspection requirements.

Acceptance Criteria

(Acceptance criteria are included.)

Inspection data is reviewed to determine whether component wall thickness falls below the "action level" for a particular component. The "action level" is typically calculated as the thickness halfway between code minimum wall thickness and the nominal wall thickness referenced by the design code of record. Wall thickness measurements falling below the "action level" are evaluated to determine proper corrective actions.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

Plant Hatch maintains awareness of FAC-related events and developments in the industry. This is accomplished through correspondence with EPRI and regular review of industry and regulatory-generated documents. Additionally, EPRI NSAC-202L considers historical data collected from industry and contains lessons learned from years of operating experience, thereby assuring that past experience has been utilized to improve the program methods.

A review of condition reports written during the past five years revealed the following applicable occurrences. Deficiency Notice CO9903259 was written to identify a pipe leak downstream of orifice 1B21-D001 between the orifice flange and the downstream elbow of the main steam line drain to the condenser. The corrective action replaced the damaged piping and fittings as well as incorporated this section of piping into the FAC program to monitor and detect any future degradation.

Several other events have been identified per the deficiency control system related to pressure boundary failures in small bore piping of the HPCI and RCIC main steam supply drain path to the condenser. All these events consisted of loss of material in piping components due to erosion–corrosion or FAC. These failures provide the evidence that these aging mechanisms are detrimental to this commodity group. The corrective action, for these operating events, consists of replacing the degraded lines with material that is not susceptible to FAC, i.e., alloy steel piping. This corrective action is complete for Unit 2 and will be completed on Unit 1 during RF019.

In-scope high-pressure drain manifold to the Unit 2 condenser was replaced with chrome-moly piping as a result of FAC program inspections, wear rate analysis and corrective action implementation. This manifold is part of in-scope function N61-03, radioactive decay hold-up volume. Within this same function, main steam drain pot drain piping to the high pressure manifold have also been replaced with FAC resistant chrome-moly piping based on FAC Program inspections and corrective actions.

References

1. *EPRI NSAC-202L R2 "Recommendations for an Effective Flow-Accelerated Corrosion Program."*

2. *EPRI TR-106611 R1 "Flow Accelerated Corrosion in Power Plants."*

3. *NRC Generic Letter 89-08, Erosion/Corrosion-Induced Pipe Wall Thinning.*

4. *Southern Company Services, "Flow-Accelerated Corrosion (FAC) Program, Hatch Nuclear Plant Units 1 and 2", Volumes 1 and 2.*

B.2.3 Protective Coatings Program

The Plant Hatch Protective Coatings Program provides a means of preventing or minimizing corrosion that would otherwise result from contact of the base material with a corrosive environment. It is a mitigation and condition monitoring program designed to provide base metal aging management through surface application, maintenance, and inspection of protective coatings on selected components and structures.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

The protective coatings program provides specifications for all coatings applied at Plant Hatch and specific inspection techniques and frequencies for service level I coatings (which include non-immersion coatings applied to the suppression chamber and drywell airspace and immersion coatings applied to the suppression chamber interior below the normal water level).

The protective coatings program will be enhanced to provide inspection techniques and frequencies for certain non-service level I coatings. The new requirements apply to external surfaces of carbon steel commodities in-scope for license renewal that are exposed to inside, outside, submerged, and buried environments and are expected to experience significant atmospheric corrosion.

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

Portions of the following systems fall under the scope of the protective coatings program:

B21- external coated surfaces including bolting
C11- external coated surfaces including bolting
C41- accumulator tank (interior surface)
E11- external coated surfaces including bolting (see Note 1)
E21- external coated surfaces including bolting
E41- external coated surfaces including bolting
E51- external coated surfaces including bolting
F15- coated steel structures
H11- coated supports
H21- coated supports
L35- coated supports
L48- coated steel structures
N61- external coated surfaces including bolting
P41- external coated surfaces including bolting (see Note 1)
P42- external coated surfaces including bolting
P52- external coated surfaces including bolting
P64- external coated surfaces including bolting
P70- external coated surfaces including bolting
R33- coated supports

T23- coated surfaces including bolting
T24- coated steel structures
T29- coated steel structures
T31- coated steel structures
T41- external coated surfaces including bolting
T46- external coated surfaces including bolting (see Note 1)
T48- external coated surfaces including bolting
T49- external coated surfaces including bolting
T54- coated steel structures
U29- coated steel structures
W33- coated steel structures and bolting
W35- coated steel structures
Y29- coated steel structures
Y32- coated steel structures
Y39- coated steel structures
X41- external coated surfaces including bolting
X43- external coated surfaces including bolting, firewater storage tanks (internal surface) (see Note 1)
Y52- external coated surfaces including bolting (see Note 1)
Z29- coated steel structures
Z41- external coated surfaces including bolting

Note 1- Buried or embedded components/structures will be inspected when they become available due to maintenance activities.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

Proper application of coatings will limit normal corrosion processes by preventing direct contact between susceptible base materials and environmental conditions conducive to corrosion.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

Periodic inspection of components is conducted in order to identify areas of degraded coatings and associated corrosion of base metals. Inspection techniques may include visual examination of components for degradation and mapping, marking and photography of areas where significant degradation is identified. Also, for surfaces determined to be suspect, dry film thickness, adhesion, and continuity tests may be performed.

When application of new coatings is required, inspection of the newly applied coatings includes visual inspections. If required, profile measurements on newly prepared surfaces and holiday testing and dry film thickness measurements on newly applied coating systems are also monitored. Finally, during coating application, ambient conditions and surface temperatures are periodically monitored to ensure suitable conditions for mixing and applying coatings are present.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

Coating degradation can occur in areas of adverse environmental conditions, such as excessive moisture or chemical impurities. Coatings inspection frequencies are determined by the Plant Hatch coatings specialist such that any age related degradation is detected prior to an impact on intended functions. Service level I coatings are inspected at set intervals. Frequencies for other coating inspections are determined using operating experience and expected environmental conditions. Coal tar enamel coatings applied to buried carbon steel components are inspected whenever these items are unearthed for maintenance.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

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 due to excavation activities. Subsequent inspection frequency will be determined based on the results of the baseline inspection.

Acceptance Criteria

(Acceptance criteria are included.)

Acceptance criteria for the protective coatings program may be categorized into 3 areas; surface preparation, coatings application, and inspection activities. Specific acceptance criteria for the protective coatings program are based on the guidance of ANSI, ASTM, and EPRI technical documentation.

Surface preparation will be performed in accordance with industry guidance listed below. Coating application is not allowed to proceed until applicable solvent cleaning; removal of stratified rust, loose mill scale, non-adherent paint, and weld flux and splatter; and thick edge paint feathering has been accomplished.

Application of coatings and subsequent curing may only occur when environmental and surface conditions are in accordance with applicable industry standards and vendor recommendations

Visual inspection after coating application confirms that the appearance and condition of the applied coating are representative of good work practices. Subsequent visual inspections to identify degradation of coatings will be performed to ensure no intended functions are inhibited.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

A review of plant deficiency cards submitted over the past five years 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 due 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 due to coating degradation over the past 5 years.

References

1. *Electric Power Research Institute TR-109937 "Guideline on Nuclear Safety-Related Components."*

2. *ANSI N5.9 – 1967, "Protective Coatings (Paints) for the Nuclear Industry."*

3. *ANSI N5.12 – 1972 "Protective Coatings (Paints) for the Nuclear Industry."*

4. *ANSI N101.2 – 1972 "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities."*

5. *ASTM Section 6, Vol. 6.02 "Paints-Products and Applications; Protective Coatings; Pipeline Coatings."*

6. *American Water Works Association (AWWA) C203 – 1966 "Standard for Coal-Tar Protective Coatings and Linings for Steel Water Pipelines – Enamel and Tape – Hot Applied."*

7. *AWWA C209 – 1995 "Cold Applied Tape Coatings for the Exterior of Special Sections, Connections, and Fittings for Steel Water Pipelines," 2nd Ed.*

B.2.4 Equipment And Piping Insulation Monitoring Program

Equipment and piping insulation performance may be degraded if the insulation or jacketing is damaged. 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.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

The Equipment and Piping Insulation Monitoring Program currently inspects outside insulation within the scope of license renewal. It will be enhanced to include portions of the following systems that are within the scope of license renewal:

C41 – SLC System
E11 – RHR and RHRSW
E21 – Core Spray
E41 – HPCI
E51 – RCIC
P11 – Condensate Transfer and Storage
P41 – PSW
X43 – Fire Protection

Program enhancements will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

Plant Hatch procedures contain precautions that mitigate insulation damage by 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.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

The Equipment and Piping Insulation Monitoring Program will be enhanced to periodically inspect in-scope insulation, that is readily accessible, for 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.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

Appropriate visual inspection techniques will be used for the inspections. These techniques will be specified in plant procedures for these inspections and 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 due to cracking, settling, and thermal degradation. None of these conditions (holes, tears, cracks, missing material, etc.) is acceptable. If degradation is discovered, corrective action must 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.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

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.

Acceptance Criteria

(Acceptance criteria are included.)

Any unacceptable indication of corrosion or insulation damage will be evaluated and, if warranted, additional inspections will be performed. Corrective actions, if required, will be addressed through the existing Plant Hatch corrective actions program.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

A review of plant deficiency cards submitted over the past 5 years did not identify any age-related degradation in insulation or insulation jacketing for the components within the scope of license renewal.

References

None.

B.2.5 Structural Monitoring Program

The Plant Hatch SMP provides a stepped, condition monitoring and appraisal process for structures and components within the scope of the Maintenance Rule (10 CFR 50.65) and the License Renewal Rule (10 CFR 54). The program is patterned after the Westinghouse Owners Group Life Cycle Management/License Renewal Program.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

The Structural Monitoring Program monitors the following structures, components and commodities. This list reflects a recent revision to the SMP to address program enhancements made as a result of license renewal.

- Switchyard (not required for License Renewal)
- Reactor Buildings
- Turbine Buildings
- Intake Structure
- Off Gas Stack
- EDG Building
- Control Building
- Waste Gas Building (not required for License Renewal)
- Condensate Storage Tanks and Retaining Walls
- PSW Valve Pits
- Diesel Fuel Storage Tanks
- Nitrogen Storage Tanks/Foundations
- Category I and II/I piping supports and tube tray supports
- Category I HVAC duct supports
- Category I and II/I cable trays and supports
- Category I and II/I conduits and supports
- Category I control room panels, racks and supports
- Category I auxiliary panels, racks and supports
- Sealants in the joints between the reactor building exterior precast siding panels
- Reactor Building tornado vents

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The SMP is a condition monitoring program that utilizes visual inspections to identify aging effects prior to any loss of intended function. As such, there are no preventive or mitigate attributes associated with this program.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

Concrete structures are inspected for cracking and spalling. Masonry block walls are inspected for cracking. Steel structures and components are inspected for corrosion. Panel joints seals and sealants are inspected for loss of adhesion, material property changes and cracking. The acrylic domes on the tornado vents will be inspected for cracking.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

The SMP inspection process assesses the ongoing, overall conditions of the buildings and structures, and identifies any ongoing degradation. Structure condition is assessed through a visual inspection. Inspections include those normally accessible, as well as those below ground or embedded. When normally inaccessible structures are exposed because of excavation or modification, an examination of the exposed surfaces is performed. 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 inspections are performed by qualified personnel, using detailed checklists, inspection tools and preparations. All inspection results are documented in checklists and noted degradation may be documented utilizing digital photography.

The inspection frequency for plant structures varies according to site conditions and susceptibility to aging degradation. As a result of the baseline inspections a five-year inspection frequency was established for the structures monitored. This frequency will continue unless the conditions, environment, or noted degradation warrant a change. At this time, the plant has elected to inspect the intake structure every operating cycle due to humid environmental conditions. However, based on the results of future intake structure inspections, the plant may elect to go back to a five-year frequency. For areas of the subject buildings and structures that are inaccessible due to physical obstruction, and below grade, embedded or buried components, inspections are performed whenever these areas are excavated, exposed or modified.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Initial inspections (baseline) were conducted to facilitate condition trending. 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 reactor building (including spent fuel areas), control building, turbine building, offgas stack, diesel building, condensate storage building, plant service water valve pits, diesel fuel storage tanks, and nitrogen storage tanks will be inspected on a 5 cycle interval. Certain areas within the reactor building will be inspected every other cycle. These include the drywell, torus (inside), and overhead cranes.

Acceptance Criteria

(Acceptance criteria are included.)

Acceptance criteria for the inspection and criteria for categorizing the overall structure and component conditions (i.e., acceptable, acceptable with deficiency, or unacceptable) are provided in the procedure. The acceptance criteria are consistent with the recommended criteria in ACI-349.3R-1996, but also include additional criteria for roof ponding, water leakage, coatings, penetration seals, etc. The results of the inspections are evaluated in accordance with the guidance given in NEI-96-03 and NRC Regulatory Guide 1.160. The results of SMP inspections are forwarded to the Maintenance Rule Coordinator who determines if any condition reports should be initiated.

The following selected acceptance criteria are detailed in the Structural Monitoring Program for acceptability of the components:

<u>Concrete Components</u>

Spalls less than 3/4" in depth and 8" in dimension

Passive cracks less than 0.040" in width, measured below any surface enhanced widening ("passive cracks" are those with no evidence of recent growth and absence of other degradation mechanisms at the crack). For cracks greater than or equal to 0.040" in width, the length of the crack will be measured / estimated and documented in the database.

<u>Concrete Embedments</u>

Corrosion on exposed embedded metal surfaces, which is not progressing and has not resulted in loss of cross section greater than 10%

<u>Concrete Joints</u>

No signs of separation or environmental degradation are present in joints or joint material

<u>Block Walls</u>

The acceptance of possible cracking in block walls should be performed considering the individual plant design analysis (IEB 80-11 or otherwise). Existing analysis may have considered some degree of cracking in the evaluation.

Lateral supports for seismic block wall should be appropriately anchored.

Interfaces between the block walls and concrete floors, walls and floors should show no evidence of damage or movement.

Steel Components

General corrosion with the presence of red iron oxide (rust), surface stains, spots or surface discoloration

General corrosion with the presence of red iron oxide (rust) particles / scale which are easily removed from surface

Localized corrosion with the presence of small diameter pitting (black iron oxide powder in pits indicates active pitting and red iron oxide powder in pits indicates inactive pitting) on exposed (coated or uncoated) metal surfaces that is not progressive

Localized corrosion with the presence of loose rust flakes peeling or blooming from metal surfaces. The loss of cross section is less than 10% and corrosion is not progressive

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

In 1996 and 1997, an initial evaluation was performed, as part of the Structural Monitoring Program, to establish a baseline condition of the subject buildings and structures. Areas within the scope of the Maintenance Rule were visually inspected and photographs were made to document notable degrees of degradation. Specific items and areas included in the inspections were the roof, settlement around the building, outer concrete walls and penetrations, interior concrete columns, beams, floors, walls, interior steel superstructure columns, girders and beams, foundations, anchor bolts, and equipment slabs. Specific items and areas also included in the inspection of the sealants were the outer pre-cast concrete wall panels and the CST transfer pump wall joints. All inspected areas were found "Acceptable - no further evaluation required." Condition surveys were conducted in April 1997 and November 1997. The inspection reports concluded the same findings as previous reports. Previous results of settlement surveys, and associated calculations, were also reviewed and all structures were found to be within acceptable settlement limits. The sealant and backing rod used to seal the joint between exterior pre-cast panels on the Unit 1 and Unit 2 reactor buildings has also been replaced to repair degraded caulking.

References

1. *A-44985, Structural Monitoring Program for the Maintenance Rule, Edwin I. Hatch Nuclear Plant, Units 1 and 2*

2. *10CFR50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."*

3. *Westinghouse Owner's Group Life Cycle Management / License Renewal Program, Altran Corporation / Altran Materials Engineering.*

4. *ACI Committee 349, Repot ACI 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures."*

5. *NEI 96-03 "Guideline for Monitoring the Condition of Structures at Nuclear Power Plants."*

6. *NRC Regulatory Guide 1.160, Rev 2 "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."*

B.3 NEW PROGRAMS AND ACTIVITIES

B.3.1 Galvanic Susceptibility Inspections

The Plant Hatch 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.

Since galvanic corrosion is most likely in commodities within environments that are more corrosive (high impurity and conductivity levels), these inspections will start with the more corrosive raw water environment.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

Galvanic Susceptibility Inspections will examine a sample population of carbon to stainless steel connections (welded and flanged) that should exhibit the largest galvanic coupling. If the examined carbon to stainless connections show galvanic corrosion, the sample set will be expanded to other water systems. Systems include:

B21 – Nuclear Boiler
C11 – CRD
E11 – RHR and RHRSW
E41 – HPCI
E51 – RCIC
N61 – Main Condenser System
P41 – PSW
R43 – EDG
T23 – Primary Containment
T48 – Containment Atmospheric Control
W33 - Screen Wash Isolation

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.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The Galvanic Susceptibility inspections will be a condition monitoring activity that utilizes various inspection methods to identify unacceptable corrosion within the selected weld couplings. As such, there are no preventive or mitigative attributes associated with this program.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

The sample set will be selected from raw water carbon to stainless connections. Examination results will be evaluated to determine whether the sample set should be expanded to other environments. Inspection locations will be based on engineering judgement and will include areas predicted to be most susceptible.

The sample size of each examination method will be a function of the sample locations and the aging effect that is suspected. All types of in-scope components will be represented in the sample population, such as piping, fittings, tubing, valves, pumps, welds, etc. as applicable to the susceptibility to the aging mechanism.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

Piping inspections will be performed using one or more methods. These may include visual, ultrasonic thickness determinations, radiographic testing, depth gauges, and pipe removal and analysis. Inspections may utilize an examination method similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210.

Inspection procedures and acceptance criteria will be developed using the applicable sections of the design codes. Where applicable, minimum wall thickness will be calculated in accordance with the piping design code, piping stress requirements, and the piping specification drawings.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

The Galvanic Susceptibility Inspection will be a one-time inspection designed to verify that galvanic corrosion is not occurring in passive components within the scope of license renewal. As such, trending is not required.

Acceptance Criteria

(Acceptance criteria are included.)

Any unacceptable indication of loss of material will be evaluated by further 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.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

The Galvanic Susceptibility Inspection will be a one-time inspection activity. As such there is no operating experience directly associated with this inspection.

However, a review of plant deficiency cards submitted over the past five years found no deficiencies in the in-scope components related to loss of material due to galvanic corrosion.

References

1. *ASME Boiler and Pressure Vessel Code.*

B.3.2 Treated Water Systems Piping Inspections

The treated water systems piping inspections will be one time condition monitoring examinations intended to prove that existing chemistry control is managing aging in piping that is not examined under another inspection program.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect. Specific commodities include, but not limited to, carbon and stainless steel piping, tubing, valve bodies, pump casings, tanks, accumulators and strainer bodies.)

Portions of the following systems are included within the scope of this program:

B21 - Nuclear Boiler
B31 - Reactor Recirculation
C11 - CRD
C41 - SLC
E21 - Core Spray
E41 - HPCI
E51 - RCIC
N32 - Main Turbine Auxiliaries
N61 - Main Condenser and Auxiliaries
P11 - Condensate Storage and Transfer
P42 - RBCCW
P64 - PCCW
R43 - EDG Auxiliaries
T23 - Primary Containment
T48 - Containment Atmospheric Control System

The Unit 1 inspections will be performed on or after August 6, 2009, but before midnight August 2014. The Unit 2 inspections will be performed on or after June 13, 2013, but before midnight June 13, 2018.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The treated water systems 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.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

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, the torus water, the demineralized water, closed cooling water, and borated water environments.

Inspection locations will be based on engineering judgement and will include areas predicted to be most susceptible to corrosion, erosion-corrosion, erosion, and cracking.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

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.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

If components do not meet the acceptance criteria defined in the inspection procedure, they will be evaluated, repaired or replaced prior to return 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.

Periodic monitoring and trending of degradation for inspection locations will be established provided the one-time inspection results indicate a concern that components may not be able to perform their intended function during the extended operation.

Failures will be required by plant procedures to be documented in accordance with the Plant Hatch corrective actions program.

Acceptance Criteria

(Acceptance criteria are included.)

Any unacceptable indication of corrosion will be evaluated by further engineering analysis. Component wall thickness acceptability will be based upon 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.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

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. However, a review of plant deficiency cards submitted over the past five years revealed no significant deficiencies in the in-scope treated water components due to age related degradation.

References

1. *ASME Boiler and Pressure Vessel Code.*

B.3.3 Gas Systems Components Inspections

The Gas Systems Component Inspections (GSCI) will be a set of one-time condition monitoring inspections designed to confirm that age-related degradation is not inhibiting component function in gas-bearing in-scope systems and components.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

Portions of the following systems are included within the scope of the GSCI:

B21 – Nuclear Boiler (In scope Safety Relief Valve Tailpipes to the Torus)
C11 – CRD
E11 – RHR
E41 – HPCI
E51 – RCIC
P33 – Sampling
R43 – EDG (Starting Air and Engine Exhaust)
T23 – Primary Containment
T41 – Reactor Building HVAC
T46 – Standby Gas Treatment
T48 – Primary Containment Purge and Inerting
T49 – Post LOCA Hydrogen Recombiners
X41 – Outside Structure HVAC
Y52 – Fuel Oil
Z41 – Control Building HVAC

A sample population of components exposed to humid and wetted gas internal environments at various temperatures will be inspected. The sample population will focus on 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 in gas bearing components of the R43, X41, and Z41 systems will be included in the sample populations. The process by which the sample population is developed will ultimately determine the actual scope of the inspections.

The Unit 1 inspections will be performed on or after August 6, 2009, but before midnight August, 2014. The Unit 2 inspections will be performed on or after June 13, 2013, but before midnight June 13, 2018.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The GSCI will be condition monitoring activities that utilize visual inspections and volumetric examinations to identify aging effects prior to any loss of intended function. As such, there are no preventive or mitigative attributes associated with this program.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

The GSCI will primarily assure that component wall thickness has not degraded such that component function is inhibited.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

The GSCI will include a sample population of the in-scope components and will use visual inspection techniques (similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210) to detect corrosion. Where possible and practical, accessible components may be inspected for stress corrosion cracking using volumetric examination methods.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

The GSCI will be one-time inspections designed to confirm that aging effects have not inhibited the functions of the inspected components. As such, no trending will be performed in these inspections.

Acceptance Criteria

(Acceptance criteria are included.)

Any unacceptable indication of corrosion will be evaluated by further engineering analysis. Component wall thickness acceptability will be based upon the component design code of record. Corrective actions, if required, will be addressed through the existing Plant Hatch Corrective Actions Program.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

The GSCI will be a new set of inspections for Plant Hatch. As such there is no operating experience directly associated with the GSCI.

However, a review of plant deficiency cards submitted over the past five years showed that no age-related deficiencies that inhibited component function have been written on components within the scope of GSCI.

References

1. *ASME Boiler and Pressure Vessel Code.*

B.3.4 Condensate Storage Tank Inspection

The CST Inspection will be a one-time condition monitoring inspection of each CST designed to provide objective evidence that no unacceptable degradation is occurring. This inspection is intended to validate the adequacy of current demineralized water chemistry controls to manage aging effects.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

The CSTs are part of P11 (Condensate Transfer and Storage). 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.

The Unit 1 inspection will be performed on or after August 6, 2009, but before midnight August, 2014. The Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The CST inspection will be 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.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

The 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 on the Unit 2 tank will focus on selected areas associated with the standpipes, associated supports, and nozzles.

Inspection locations will be based on engineering judgement and will include areas predicted to be most susceptible to corrosion such as weld heat affected zones and crevices.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

The CST Inspection will utilize visual inspection techniques (similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210) to detect corrosion.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

The CST Inspection will be a one-time inspection designed to validate the adequacy of demineralized water chemistry control in minimizing corrosion. As such, trending will not be required.

Acceptance Criteria

(Acceptance criteria are included.)

Any unacceptable indication of corrosion will be evaluated by further 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.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

The CST Inspection will be a one-time inspection activity. As such there is no operating experience directly associated with the CST Inspection. However, a review of plant deficiency cards submitted over the past five years found no age-related deficiencies of in scope CST surfaces.

References

1. ASME Boiler and Pressure Vessel Code.

B.3.5 Passive Components Inspection Activities

The PCIA will be a set of on-going condition monitoring inspections designed to confirm that age-related degradation is not inhibiting component function predominantly in gas-bearing in-scope systems and components. Piping and valves between the drywell sump and the liquid radwaste system are also included in the scope of the PCIA. These pipes and valves serve as part of the primary containment and are not otherwise in-scope for license renewal. The PCIA will also be used for aging management of buried piping and for gaskets associated with the Control Building HVAC system. The PCIA will be invoked when the normally inaccessible surfaces of these components are made available for inspection due to maintenance and other activities.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

Portions of the following systems are included within the scope of the PCIA:

B21 – Nuclear Boiler (In-scope Safety Relief Valve Tailpipes to the Torus)
C11 – CRD
E11 – RHR (Including Buried Components)
E41 – HPCI
E51 – RCIC
P41 – PSW (Buried or Embedded Components)
R43 – EDG (Starting Air and Engine Exhaust)
T23 – Primary Containment (Including the Drain Lines for the Drywell Sump Discharge)
T41 – Reactor Building HVAC
T46 – Standby Gas Treatment (Including Buried or Embedded Components)
T48 – Primary Containment Purge and Inerting
T49 – Post LOCA Hydrogen Recombiners
X41 – Outside Structure HVAC
X43 – Fire Protection (Buried or Embedded Components)
Y52 – Fuel Oil (Including Buried or Embedded Components)
Z41 – Control Building HVAC (Including gaskets)

When in-scope components are scheduled for maintenance, an evaluation will be performed to determine if the normally inaccessible surfaces should be inspected for the effects of aging. 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 the E11, P41, T46, X43, and Y52 systems will be included in the inspections.

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The PCIA will be condition monitoring activities that utilize visual inspections and volumetric examinations to identify aging effects prior to any loss of intended function. As such, there are no preventive or mitigative attributes associated with these activities.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

For metallic components, the PCIA will primarily ensure that component wall thickness has not degraded such that component function is inhibited. For gaskets, the PCIA will inspect for the presence of cracks or degradation.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

The PCIA will include a baseline examination of the in-scope components, as they become available due to normal maintenance activities. The PCIA will use visual inspection techniques (similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210) to detect corrosion of metallic components and material property changes and cracking of gaskets. Where possible and practical, accessible components may be inspected for stress corrosion cracking using volumetric examination methods.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

The PCIA will be designed to collect, report, and trend age-related data. These inspections are a further prudent measure that will assist in the early discovery of aging effects so that corrective actions may be taken before the effects inhibit component functions.

PCIA is based on availability, not population. As such, population, frequency, and sample size are not pre-determined

Acceptance Criteria

(Acceptance criteria are included.)

Any unacceptable indication of corrosion will be evaluated by further engineering analysis. Component wall thickness acceptability will be based upon the component design code of record. If the gaskets exhibit changes in material properties or cracking, then corrective action will be taken. Corrective actions, if required, will be addressed through the existing Plant Hatch Corrective Actions Program.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

The PCIA will be a new set of inspections for Plant Hatch. As such there is no operating experience directly associated with the PCIA.

However, a review of plant deficiency cards submitted over the past five years showed that no age-related deficiencies that inhibited component function have been written on components within the scope of PCIA.

References

1. *ASME Boiler and Pressure Vessel Code.*

B.3.6 RHR Heat Exchanger Augmented Inspection And Testing Program

The Plant Hatch RHR Heat Exchanger Augmented Inspection and Testing Program is a condition monitoring program that includes both existing and enhanced activities to manage aging of shell and tube sides of the Unit 1 and Unit 2 RHR Heat Exchangers.

The program partially satisfies the requirements of Nuclear Regulatory Commission Generic Letter 89-13, July 18, 1989. SNC used the guidance of SAND 93-7070. UC-523, *Aging Management Guideline for Commercial Nuclear Power Plants - Heat Exchangers* (July 1994), as supplemented by reviews of current industry experience and practice, as the basis for this program.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

The subject program will inspect, test, and/or maintain passive components of the Unit 1 and 2 RHR Heat Exchangers that are within the scope of the license renewal. These components are part of the following system:

E11 – Residual Heat Removal

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The existing activity requires that heat exchanger tubes and channel interior be cleaned at a periodic basis, every 3 cycles. This cleaning of the heat exchanger tubes and channel head mitigates flow blockage and loss of thermal performance by keeping debris out of the tubes and channel interior.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

Parameters inspected or monitored are the following: loss of material, flow area reduction due to fouling, and cracking. These parameters are linked to the degradation of component intended function.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

The following existing activities at prescribed frequencies will be continued to detect aging effects of the heat exchanger passive components.

Visual inspection of channel side (including partition plate and tube sheet) and tube interior is performed every three cycles. The frequency may be changed based on the trend and engineering evaluation. This activity will detect loss of material, flow blockage (fouling), and cracking.

The following new activities will be performed at prescribed frequencies to augment the existing activities. These new activities will be fully implemented no later than midnight August 6, 2014 and midnight June 13, 2018 for Units 1 and 2, respectively.

Eddy Current Testing will be performed at least once during each 10-year inspection interval and whenever leaks are suspected in tubes and/or tube sheet. This activity will detect loss of material, cracking and flow blockage (fouling).

The shell side of the tube sheets, shell internals, and impingement plates will be visually inspected once per 10-year inspection interval, where accessible. This activity will detect loss of material, flow blockage (fouling), and cracking.

Tube and tube sheet leak testing will be performed whenever leaks are suspected. This activity will detect leaks due to cracking and loss of material.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

If the monitored parameters in the inspection locations fall below acceptance criteria, repair and/or replacement is performed prior to the system returning to service unless an engineering analysis allows further operation. Corrective actions are implemented per plant Corrective Actions Program. The frequency of the inspection or test may be adjusted based on observed trends of the monitored parameters.

Acceptance Criteria

(Acceptance criteria are included.)

The measured or recordable values of the inspected or monitored parameters shall not fall below the acceptable values for inspection locations as defined by the program. All measured or recordable values are reviewed by engineering against appropriate acceptance criteria for proper disposition. The bases for acceptance criteria are documented.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

A review of the condition reporting database revealed one significant event for RHR Heat Exchangers. During 1996, a sample taken from a RHRSW drain valve contained the presence of nuclides. A root cause investigation and subsequent helium leak test and eddy current testing performed on the 1E11-B001B RHR heat exchanger identified possible leakage in nine heat exchanger tubes. One was a known leaker and the other eight were suspected leakers. Subsequent inspection of the tube bundle revealed that, other than the leaking tubes, the tube bundle was in good condition and suitable for continued service. Subsequently, the nine leaking or suspected leaking tubes were plugged.

In addition, dents were noted at the tube to tube support connections of many tubes and may have been indicative of tube vibration. However, since no exact cause for the tube leakage was identified, the isolated damage could also be due to mill flaws or defects created during bundle assembly or installation and not related to any aging effect. The damaged areas are minor in nature and no subsequent 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 five-year period under consideration.

References

1. *Nuclear Regulatory Commission Generic Letter 89-13, July 18, 1989.*

2. *SAND93-7070 – Aging Management Guideline for Commercial Nuclear Power Plants – Heat Exchangers, June 1994.*

B.3.7 Torus Submerged Components Inspection Program

The Torus Submerged Components Inspection Program is a condition monitoring activity designed to provide objective evidence that no unacceptable degradation is occurring. This inspection is intended to validate the adequacy of current suppression pool chemistry controls to manage aging effects.

Program Scope

(Scope of the program includes the specific structure, component, or commodity for the identified aging effect.)

Portions of the following systems are within the scope of the Torus Submerged Components Inspection Program:

B21 – Nuclear Boiler
E11 – RHR
E21 – Core Spray
E41 – HPCI
E51 – RCIC
T48 – Primary Containment Purge and Inerting

Components and structures inspected by the Torus Submerged Components Inspection Program include emergency core cooling system suction strainers, reactor core isolation cooling system suction strainers, submerged portions of safety relief valve piping, ECCS turbine steam exhaust piping, and vacuum relief piping.

(The Torus Submerged Components Inspection Program will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2.)

Preventive or Mitigative Actions

(Preventive actions to mitigate or prevent aging degradation.)

The Torus Submerged Components Inspection Program is a condition monitoring activity that utilizes visual inspections to identify unacceptable corrosion on components submerged within the suppression pool. As such, there are no preventive or mitigative attributes associated with this program.

Parameters Inspected or Monitored

(Parameters inspected or monitored are linked to the degradation of the particular intended function.)

Uncoated components and structures submerged within the suppression pool and in the vapor space directly above the suppression pool will be visually inspected for indications of corrosion by the Torus Submerged Components Inspection Program. Inspection locations will be based on engineering judgement and will include areas predicted to be most susceptible to corrosion such as weld heat affected zones and crevices.

Detection of Aging Effects

(The method of detection of the aging effects is described and performed in a timely manner).

The Torus Submerged Components Inspection Program will utilize visual inspection techniques (similar to that described for VT-1 in ASME Section XI, paragraph IWA-2210) to detect corrosion.

Monitoring and Trending

(Monitoring and trending provide for timely corrective actions.)

Results of Torus Submerged Components Inspection Program inspections will be documented in accordance with Plant Hatch procedural requirements. The Plant Hatch corrective actions program will be utilized to monitor and trend deficiencies and to implement timely corrective actions. A baseline examination will be performed for each unit prior to entering the period of extended operation. The scope and frequency of any subsequent examinations will be based on the results of these baseline inspections and any additional past operating experience available.

Acceptance Criteria

(Acceptance criteria are included.)

Any unacceptable indication of corrosion will be evaluated by further 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.

Operating Experience

(Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, is considered.)

The Torus Submerged Components Inspection Program is a new program with no existing operating experience. However, results of recent inspections in the Torus, conducted as a part of the protective coatings program, did not identify any significant degradation due to corrosion.

References

1. *ASME Boiler and Pressure Vessel Code.*