NUREG-1785

Safety Evaluation Report
Related to the License Renewal of H.B. Robinson Steam Electric Plant, Unit 2

Docket No. 50-261

Carolina Power & Light Company

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, DC 20555-0001

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ABSTRACT

This safety evaluation report (SER) documents the technical review of the H.B. Robinson Steam Electric Plant (HBRSEP), Unit No. 2, known as Robinson Nuclear Plant (RNP), license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff. By letter dated June 14, 2002, Carolina Power & Light Company (CP&L or the applicant) submitted the LRA for RNP in accordance with Title 10 of the *Code of Federal Regulations* Part 54 (10 CFR Part 54 or the Rule). RNP is requesting renewal of the operating license for Unit 2 (License Number DPR-23) for a period of 20 years beyond the current expiration date of midnight, July 31, 2010. The construction permit for RNP was issued by the NRC on April 13, 1967, and the operating license was issued September 23, 1970, pursuant to Section 104b of the Atomic Energy Act of 1954, as amended.

RNP is adjacent to Unit 1 of the H.B. Robinson Steam Electric Plant (SEP), a coal-fired steam power plant. The plant is located on the edge of Lake Robinson, a man-made lake in Darlington and Chesterfield Counties, South Carolina. RNP is a pressurized light-water moderated and cooled system. The nuclear power plant incorporates a three-loop closed-cycle, pressurized water, nuclear steam supply system designed by (NSSS) Westinghouse Electrical Corporation and licensed to generate 2339 MW-thermal, or approximately 769 MW-electric.

This SER presents the status of the staff's review of information submitted to the NRC through January 21, 2004. In it's SER issued August 25, 2003, the staff has identified open and confirmatory items that had to be resolved before the staff could make a final determination on the application. These items and their resolutions are summarized in Sections 1.5 and 1.6 of this report. The staff's final conclusion of it's review of the RNP LRA can be found in Section 6 of this SER.

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ABBREVIATIONS

AC	alternating current
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards (NRC)
AFW	auxiliary feedwater
AISC	American Institute of Steel Construction
AISI	American Iron and Steel Institute
ALARA	as low as reasonably achievable
AMP	aging management program
AMR	aging management review
ANL	Argonne National Laboratory
ANSI	American National Standards Institute
API	American Petroleum Institute
ASA	American Standards Association
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
AWWA	American Water Works Association
B&PV	boiler and pressure vessel
BIT	boron injection tank
BMI	bottom mounted instrumentation
BTP	branch technical position
BWR	boiling-water reactor
CASS	cast austenitic stainless steel
CCMS	core cooling monitor system
CE	Combustion Engineering, Inc.
CETS	core exit thermocouple system
CF	chemistry factor
CRD	control rod drive
CCW	component cooling water
CFR	Code Of Federal Regulations
CLB	current licensing basis
CMAA	Crane Manufacturers Association of America
CP&L	Carolina Power & Light Co.
CRDM	control rod drive mechanism
CSS	containment spray system
CST	condensate storage tank
CUF	cumulative usage factor
CV	containment vessel
CVCS	chemical and volume control system
DBA	design basis accident
DBD	design basis document
DBE	design basis earthquake
dc	direct current

DG	diesel generator
DOE	Department of Energy, U.S.
DS	dedicated shutdown
DSDG	dedicated shutdown diesel generator
EAF	environmentally assisted fatigue
ECCS	emergency core cooling system
EDB	equipment database
EOCI	electric overhead crane institute
ESS	extraction steam system
ET	eddy current testing (NRC List of Abbreviations has this as ECT)
EDG	emergency diesel generator
EFPY	effective full-power years
EHC	electrohydraulic control
EJMA	expansion joint manufacturers association
EMA	equivalent margins analysis
EOF	emergency operations facility
EPRI	Electric Power Research Institute
EQ	environmental qualification
ER	environmental report
ESF	engineered safety features
FAC	flow-accelerated corrosion
F_{en}	environmental fatigue multiplier
FERC	Federal Energy Regulatory Commission
FMP	fatigue monitoring program
FP	fire protection
FPC	Florida Power Corporation
FR	*Federal Register*
FHB	fuel-handling building
FSAR	final safety analysis report
FW	Feedwater
GALL	Generic Aging Lessons Learned (GALL) Report, NUREG–1801
GEIS	generic environmental impact statement
GDC	general design criterion/criteria
GL	generic letter
GSI	generic safety issue
HAD	heat-actuated device
HBRNS	H.B. Robinson Nuclear Station
HEPA	high-efficiency particulate air
HELB	high energy line break
HPSI	high pressure safety injection
HVAC	heating, ventilation, and air conditioning
I&C	Instrumentation and control
IA	instrument air
IASCC	irradiation assisted stress corrosion cracking
IEEE	Institute of Electrical and Electronic Engineers
IGA	intergranular attack
IGSCC	intergranular stress-corrosion cracking
IR	insulation resistance
ISG	interim staff guidance

ILRT	integrated leak rate test (Containment Type A Test)
IN	Information Notice
INPO	Institute Of Nuclear Power Operations
IPA	integrated plant assessment
ISI	inservice inspection
IVSW	isolation valve seal water
LBB	Leak before break
LOCA	loss-of-coolant accident
LR	license renewal
LRA	license renewal application
MRP	Material Reliability Project (EPRI)
MSS	main steam system
MCC	Motor control center
MDAFW	motor-driven auxiliary feedwater
MIC	microbiologically induced corrosion
MOV	motor-operated valve
MSIV	main steam isolation valve
NACE	National Association of Corrosion Engineers
NDE	nondestructive examination
NEPA	National Environmental Policy Act of 1969
NPAR	nuclear plant aging research
NPS	nominal pipe size
NUREG	NRC technical report designation (Nuclear Regulatory Commission)
NEI	Nuclear Energy Institute
NEMA	National Electrical Manufacturer's Association
NFPA	National Fire Protection Association
NRC	Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
OE	operating experience
OCB	oil circuit breaker
P&I	piping and instrumentation
PMAMP	preventive maintenance aging management program
PAP	personnel access portal
pH	concentration of hydrogen ions
PM	preventive maintenance
PORV	power-operated relief valve
PPS	penetration pressurization system
PRT	pressurizer relief tank
P-T	pressure-temperature
PTS	pressurized thermal shock
PVC	polyvinyl Chloride
PWR	pressurized water reactor
PWSCC	primary water stress corrosion cracking
PWST	primary water storage tank
PZR	pressurizer
QA	quality assurance
QC	quality control
RAB	reactor auxiliary building
RAI	request for additional information

RCDT	reactor coolant drain tank
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
REDS	radioactive equipment drain system
RG	regulatory guide
RHR	residual heat removal
RMS	radiation monitoring system
RNP	Robinson Nuclear Plant
RO/RFO	refueling outage
RPS	reactor protection system
RPV	reactor pressure vessel
RT_{PTS}	reference temperature, pressurized thermal shock
RTS	reactor trip system
RV	reactor vessel
RWST	refueling water storage tank
RTD	resistance temperature detector
RVLIS	reactor vessel level instrumentation system
scss	steam cycle sampling system
SEP	steam electric plant
SGB	steam generator blowdown
SGBS	steam generator blowdown system
SGTR	steam generator tube rupture
SOC	Statement of Consideration
SRP-LR	Standard Review Plan for License Renewal
SUT	startup transformer
SAR	safety analysis report
SBO	station blackout
SCs	structures and components
SCC	stress corrosion cracking
SDAFW	steam-driven auxiliary feedwater
SER	safety evaluation report
SFP	spent fuel pit
SG	steam Generator
SI	safety injection
SIT	structural integrity test
SR	silicone rubber
SRP	standard review plan
SSCs	systems, structures, and components
SFPCS	spent fuel pit cooling system
SWS	service water system
TDR	time domain reflectometry
TGSCC	transgranular stress corrosion cracking
TID	total integrated dose
TLAA	time-limited aging analysis
TSC	Technical Support Center
UAT	unit auxiliary transformer
UV	ultraviolet
UFSAR	Updated Final Safety Analysis Report

USAS	United States Of America Standards
USE	Upper Shelf Energy
UT	ultrasonic test
Vac	volts alternating current
Vdc	volts direct current
VHP	vessel head penetration
VCT	volume control tank
WCAP	Westinghouse Commercial Atomic Power
WDS	waste disposal system
WOG	Westinghouse Owner's Group

1 Introduction and General Discussion

1.1 Introduction

This document is a safety evaluation report (SER) on the application for license renewal for the H.B. Robinson Steam Electric Plant, Unit No. 2 (RNP), as filed by the Carolina Power & Light Company (CP&L or the applicant). By letter dated June 14, 2002, CP&L submitted its application to the U.S. Nuclear Regulatory Commission (NRC or the Agency) for renewal of the RNP operating license for an additional 20 years. The NRC staff (the staff) prepared this report which summarizes the results of its safety review of the renewal application for compliance with the requirements of Title 10, Part 54 of the *Code of Federal Regulations* (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." The NRC license renewal project manager for the RNP license renewal review is Mr. Sikhindra K. Mitra. Mr. Mitra may be contacted by calling 301-415-2783, or by writing to the License Renewal and Environmental Impacts Program, U.S. Nuclear Regulatory Commission, Mail Stop O-11F1, Washington, D.C. 20555-0001.

In its June 14, 2002, submittal letter, CP&L requested renewal of the operating license issued under Section 104b of the Atomic Energy Act of 1954, as amended, for RNP (License Number DPR-23) for a period of 20 years beyond the current license expiration date of July 31, 2010. RNP is adjacent to Unit 1 of the H.B. Robinson Steam Electric Plant, a coal-fired steam power plant. RNP is located on Lake Robinson, a man-made lake in Darlington and Chesterfield Counties, South Carolina. RNP is a pressurized light-water-moderated and cooled system. The nuclear power plant incorporates a three-loop closed-cycle, pressurized water, nuclear steam supply system (NSSS) designed by Westinghouse Electric Corporation and licensed to generate 2339 Mw-thermal, or approximately 769 Mw-electric. Details concerning the plant and the site are found in the Updated Final Safety Analysis Report (UFSAR) for RNP.

The license renewal process proceeds along two tracks—a technical review of safety issues and an environmental review. The requirements for these reviews are stated in NRC regulations 10 CFR Parts 54 and 51, respectively. The safety review for the RNP license renewal is based on the applicant's license renewal application (LRA), RNP UFSAR and on the answers to requests for additional information (RAIs) from the staff. In meetings and docketed correspondence, the applicant has also supplemented its LRA and answers to the RAIs. The LRA and all pertinent information and materials, including the UFSAR mentioned above, are available to the public for review at the NRC Public Document Room, 11555 Rockville Pike, Room 1-F21, Rockville, MD 20852-2738 (301-415-4737/800-3974209). Material related to the LRA is also available through the NRC's website, at www.nrc.gov.

This SER summarizes the results of the staff's safety review of the RNP LRA and delineates the scope of the technical details considered in evaluating the safety aspects of RNP's proposed operation for an additional 20 years beyond the term of the current operating license. The LRA was reviewed in accordance with the NRC regulations and the guidance provided in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," dated July 2001 (SRP-LR).

Sections 2 through 4 of the SER address the staff's review and evaluation of license renewal issues that have been considered during the review of the application. Section 5 is reserved for the report of the Advisory Committee on Reactor Safeguards (ACRS). The SER conclusions are in Section 6 of this document.

Appendix A of this SER is a table that identifies the applicant's commitments associated with the renewal of the operating license. Appendix B is a chronology of the NRC's and the applicant's principal correspondence related to the review of the applications. Appendix C is a list of the NRC staff's principal reviewers and its contractors for this project. Appendix D is a list of the major references used in support of this SER.

In accordance with 10 CFR Part 51, the staff prepared a draft for comment on the plant-specific supplement to the Generic Environmental Impact Statement (GEIS) that discusses the environmental considerations related to renewing the license for RNP. NUREG-1437, Supplement 13, the plant-specific draft supplement to the GEIS, was issued on May 5, 2003. The final supplement to the GEIS was issued in December 2003.

1.2 License Renewal Background

Pursuant to the Atomic Energy Act of 1954, as amended, and NRC regulations, licenses for the operation of commercial power reactors are issued for 40 years. These licenses can be renewed for up to 20 additional years. The original 40-year license term was selected on the basis of economic and antitrust considerations, rather than technical limitations. However, some plant equipment may have been designed on the basis of an expected 40-year service life.

In 1982, the NRC anticipated interest in license renewal and held a workshop on the aging of nuclear power plants. This workshop led the NRC to establish a comprehensive program for nuclear plant aging research (NPAR). As a result of this research, a technical review group concluded that many aging phenomena are readily manageable and do not involve technical issues that would preclude extending the life of nuclear power plants. In 1986, the NRC published a request for comments regarding a policy statement on major policy, technical, and procedural issues related to license renewal for nuclear power plants.

In 1991, the NRC published a license renewal rule in 10 CFR Part 54 (the Rule). The NRC participated in an industry-sponsored demonstration program to apply the Rule to a pilot plant and to develop experience to establish implementation guidance. To establish a scope of review for license renewal, the Rule defined age-related degradation unique to license renewal. However, during the demonstration program, the NRC found that many aging mechanisms occur and are managed during the period of the initial license. In addition, the NRC found that the scope of the review did not allow sufficient credit for existing programs, particularly the implementation of the maintenance rule, which also manages plant aging phenomena. As a result, in 1995, the NRC amended the license renewal rule. The amended 10 CFR Part 54 established a regulatory process that is simpler, more stable, and more predictable than the previous license renewal rule. In particular, 10 CFR Part 54 was amended to focus on managing the adverse effects of aging rather than on identifying age-related degradation unique to license renewal. The rule changes were intended to ensure that important systems, structures, and components (SSCs) will continue to perform their intended functions in the period of extended operation. In addition, the integrated plant assessment (IPA) process was clarified and simplified to be consistent with the revised focus on passive, long-lived structures and components (SCs).

In parallel with these efforts, the NRC pursued a separate rulemaking effort, 10 CFR Part 51, to focus the scope of the review of the environmental impacts of license renewal, in fulfillment of the NRC's responsibilities under the National Environmental Policy Act of 1969 (NEPA).

1.2.1 Safety Review

License renewal requirements for power reactors are based on two principles:

(1) The regulatory process is adequate to ensure that the licensing bases of all currently operating plants provide and maintain an acceptable level of safety, with the possible exception of the detrimental effects of aging on the functionality of certain system, structures, and components during the period of extended operation and a few other safety issues.

(2) The plant-specific licensing basis must be maintained during the renewal term in the same manner, and to the same extent, as during the original licensing term.

In implementing these two principles, 10 CFR 54.4 defines the scope of license renewal as including those plant SSCs (a) that are safety related, (b) nonsafety related whose failure could affect safety-related functions, and (c) that are relied on to demonstrate compliance with the Commission's regulations for fire protection (FP), environmental qualification (EQ), pressurized thermal shock (PTS), anticipated transients without scram (ATWS), and station blackout (SBO).

Pursuant to 10 CFR 54.21(a), an applicant for a renewed license must review all SSCs within the scope of the Rule to identify SCs that are subject to an aging management review (AMR). SCs subject to an AMR are those that perform an intended function without moving parts or without a change in configuration or properties, and that are not subject to replacement based on a qualified life or a specified time period. As required by 10 CFR 54.21(a), an applicant for a renewed license must demonstrate that the effects of aging will be managed in such a way that the intended functions of the SCs within the scope of license renewal will be maintained, consistent with the current licensing basis (CLB), for the period of extended operation. Active equipment, however, is considered to be adequately monitored and maintained by existing programs. In other words, the detrimental effects of aging on active equipment are more readily detectable and will be identified and corrected through routine surveillance, performance indicators, and maintenance. The surveillance and maintenance programs for active equipment, as well as other aspects of maintaining plant design and licensing basis, are required throughout the period of extended operation. Section 54.21(d) of the Rule requires that a supplement to the final safety analysis report (FSAR) contain a summary description of the programs and activities for managing the effects of aging be submitted by the applicant.

Another requirement for license renewal is the identification and updating of time-limited aging analyses (TLAAs). During the design phase for a plant, certain assumptions are made about the initial operating term of the plant, and these assumptions are incorporated into design calculations for some of the plant's SSCs. In accordance with 10 CFR 54.21(c)(1), these calculations must be shown to be valid for the period of extended operation or projected to the end of the period of extended operation, or the applicant must demonstrate that the effects of aging of these SSCs will be adequately managed for the period of extended operation.

In 2001, the NRC developed and issued Regulatory Guide (RG) 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses." This guide endorses an implementation guideline prepared by the Nuclear Energy Institute (NEI) as an acceptable method of implementing the license renewal rule. The NEI guideline, issued in March 2001, is NEI 95-10, Revision 3, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54—The License Renewal Rule." The NRC also prepared the SRP-LR which, along with the RG 1.188, was used to review this application.

CP&L utilizes the process defined in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," dated July 2001. The purpose of GALL is to provide the staff with a summary of staff-approved aging management programs (AMPs) for the aging of most structures and components that are subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources used to review an applicant's LRA will be greatly reduced, thereby improving the efficiency and effectiveness of the license renewal review process. The GALL Report summarizes the aging management evaluations, programs, and activities credited for managing aging for most of the structures and components used throughout the industry, and serves as a reference for both applicants and staff reviewers to quickly identify those aging management programs and activities that the staff has determined will provide adequate aging management during the period of extended operation.

1.2.2 Environmental Review

The environmental protection regulation, 10 CFR Part 51, was revised in December 1996 to facilitate the environmental review for license renewal. The staff prepared a GEIS in which it examined the possible environmental impacts associated with renewing licenses of nuclear power plants. For certain types of environmental impacts, the GEIS establishes generic findings that are applicable to all nuclear power plants. These generic findings are identified as Category 1 issues in 10 CFR Part 51, Subpart A, Appendix B. Pursuant to 10 CFR 51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings into its environmental report. Analyses of those environmental impacts that must be evaluated on a plant-specific basis (Category 2 issues) must be included in the environmental report, in accordance with 10 CFR 51.53(c)(3)(ii).

In accordance with NEPA and the requirements of 10 CFR Part 51, the staff performed a plant-specific review of the environmental impacts of license renewal, including whether new and significant information existed that was not considered in the GEIS. As part of the NRC environmental scoping process, a public meeting was held near RNP on September 25, 2002, in Hartsville, SC, to identify environmental issues specific to the plant. Results of the environmental review and a preliminary recommendation with respect to the license renewal action were documented in the NRC's draft plant-specific supplement to the GEIS for RNP, which was issued by the NRC in May 2003. After considering comments on the draft, the NRC prepared NUREG-1437, Supplement 13, "Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants," which was published in December 2003.

1.3 Principal Review Matters

The requirements for renewing operating licenses for nuclear power plants are described in

10 CFR Part 54. The staff performed its technical review of the RNP LRAs in accordance with Commission guidance and the requirements of 10 CFR Part 54. The standards for renewing a license are contained in 10 CFR 54.29. This SER describes the results of the staff's safety review.

In 10 CFR 54.19(a), the Commission requires a license renewal applicant to submit general information. The applicant provided this general information in Section 1 to its letter of June 14, 2002, forwarding its applications for renewed operating licenses for H.B. Robinson Steam Electric Plant Unit 2. The staff reviewed Section 1 and found that the applicant submitted the information required by 10 CFR 54.19(a).

In 10 CFR 54.19(b), the Commission requires that license renewal applications include "conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license." The applicant states the following in its LRA regarding this issue:

> The current indemnity agreement for H.B. Robinson Steam Electric Plant Unit 2 states in Article VII that the agreement shall terminate at the time of expiration of that license specified in Item 3 of the Attachment to the agreement. Item 3 of the Agreement to the indemnity agreement, as revised by Amendment No. 1, lists H.B. Robinson Operating License DPR-23. CP&L requests that conforming changes be made to the indemnity agreement, and/or the Attachment to that agreement, specifying the extension of agreement until the expiration date of the renewed H.B. Robinson operating license as sought in this application. In addition, should the license number be changed upon issuance of the renewed license, CP&L requests that conforming changes be made to the Attachment and any other sections of the indemnity agreement as appropriate.

The staff intends to maintain the license type and number upon issuance of the renewed license. Therefore, there is no need to make conforming changes to the indemnity agreement, and the requirements of 10 CFR 54.19(b) have been met.

In 10 CFR 54.21, the Commission requires that each application for a renewed license for a nuclear facility must contain (a) an IPA, (b) a description of CLB changes during staff review of the application, (c) an evaluation of TLAAs, and (d) an FSAR Supplement. Sections 2, 3 and 4 of the LRA address the license renewal requirements of 10 CFR 54.21(a), (c), and (d), respectively.

In 10 CFR 54.21(b), the Commission requires that each year following submittal of the application, and at least 3 months before the scheduled completion of the staff's review, an amendment to the renewal application must be submitted that identifies any change to the CLB of the facility that materially affects the contents of the license renewal application, including the FSAR Supplement. This information was provided by letter dated June 25, 2003. Therefore, the requirements of 10 CFR 54.21(b) have been met.

In 10 CFR 54.22, the Commission lists requirements regarding technical specifications. In Appendix D of the LRA, the applicant stated that no changes to the RNP technical specifications are necessary. This adequately addresses the requirements of 10 CFR 54.22.

The staff evaluated the technical information required by 10 CFR 54.21 and 10 CFR 54.22 in accordance with the NRC's regulations and the guidance provided by the SRP-LR. The staff's evaluation of the LRA, in accordance with 10 CFR 54.21 and 10 CFR 54.22, is contained in Sections 2, 3, and 4 of this report.

The staff's evaluation of the environmental information required by 10 CFR 54.23 is included in the draft, and the final plant-specific supplements to the GEIS state the considerations related to renewing the license for RNP. When the report of the ACRS, required by 10 CFR 54.25, is issued, it will be incorporated into Section 5 of this SER. The findings required by 10 CFR 54.29 are included as Section 6 of this report.

1.3.1 Westinghouse Topical Reports

In the LRA the applicant referenced certain Westinghouse Commercial Atomic Power (WCAP) reports. In accordance with 10 CFR 54.17(e), the applicant referenced the following WCAP reports in the LRA:

- WCAP-10322, Revision No. 1, "Stress Report of 312 Standard Reactor Core Support Structures and Internal Structures Structural and Fatigue Analysis," October 1984
- WCAP-12962, Supplement 1, "Structural Evaluation of the H.B. Robinson Unit 2 and Shearon Harris Pressurizer Surge Lines, Considering the Effects of Thermal Stratification," October 1995
- WCAP-13587, Revision No. 1, "Reactor Vessel Upper Shelf Energy Bounding Evaluation for Westinghouse Pressurized Water Reactors", September 1993
- WCAP-14209, "Evaluation of the Effects of Insurge/Outsurge Transients of the Integrity of the Pressurizer at H.B. Robinson Unit 2," October 28, 1994
- WCAP-15338, "A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants," March 2000
- WCAP-15363, Revision No. 1, "A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of H.B. Robinson Unit 2 for the License Renewal Program," July 2002
- WCAP-15628, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the H.B. Robinson Unit 2 Nuclear Power Plant for the License Renewal Program," July 2001

The applicant states that in support of license renewal, a new report, WCAP-15363, Revision No. 1, was prepared. WCAP-15363, Revision No. 1, supercedes WCAP-15363, Revision 0, and includes an evaluation of the plant-specific pump casing material properties.

The safety evaluations of the topical reports are intended to be stand alone documents. An applicant that incorporates the topical reports by reference into an LRA must ensure that the conditions of approval stated in the safety evaluations are met. The staff's evaluation of the applicant's incorporation of the topical reports into the application is documented in Section 3 of this SER.

1.4 Interim Staff Guidance

The license renewal program is a living program. The NRC staff, industry, and other interested stakeholders gain experience and develop lessons learned with each renewed license. The lessons learned address the NRC's performance goals of maintaining safety, improving effectiveness and efficiency, reducing regulatory burden, and increasing public confidence. The lessons learned are captured in interim staff guidance (ISG) for use by the staff and interested stakeholders until the improved license renewal guidance documents are revised.

The current set of relevant ISGs that have been issued by the staff and the SER sections where the issues are addressed are provided below.

ISG Issue (Approved ISG No.)	**Purpose**	**SER Section**
Station Blackout (SBO) Scoping **(ISG-02)**	The license renewal rule 10 CFR 54.4(a)(3) includes 10 CFR 50.63(a)(1)-SBO. The SBO rule requires that a plant must withstand and recover from an SBO event. This includes recovery of offsite power. The offsite power system should be included within the scope of license renewal.	2.5.4 3.6.2.4.3 3.6.2.4.4 3.6.2.4.5
Concrete Aging Management Program **(ISG-03)**	Lessons learned from the GALL Demonstration Project indicated that GALL is not clear whether concrete needs any AMPs.	3.5.2.4.1

Fire Protection System Piping **(ISG-04)**	To clarify staff position for wall thinning of FP piping system in GALL AMPs (XI.M26 and XI.M27). New position is that there is no need to disassemble FP piping, as oxygen can be introduced in the FP piping which can accelerate corrosion. Instead, use nonintrusive method such as volumetric inspection. Field service testing of sprinkler heads should be performed at 50 years and every 10 years after initial field service testing. Eliminated Halon/carbon dioxide system inspections for charging pressure, valve line ups, and automatic mode of operation tests from GALL, as the staff considers these test verifications to be operational activities.	2.3.3.15 3.3.2.3.3.2

Identification and Treatment of Electrical Fuse Holder **(ISG-05)**	To include fuse holder AMR and AMP (i.e., same as terminal blocks and other electrical connections). The position includes only fuse holders that are not inside the enclosure of active components (e.g., inside of switchgears and inverters). Operating experience finds that metallic clamps (spring-loaded clips) have a history of age-related failures from aging stressors such as vibration, thermal cycling, mechanical stress, corrosion, and chemical contamination. The staff finds that visual inspection of fuse clips is not sufficient to detect the aging effects from fatigue, mechanical stress and vibration.	3.6.2.3.1

1.5 Summary of Open Items

As a result of its review of the LRA for RNP, including additional information submitted to the NRC through April 28, 2003, the staff identified the following issues that remained open at the time this report was prepared. An issue was open if the applicant had not presented a sufficient basis for resolution. Each open item has been assigned a unique identifying number. The items identified in this section have been properly closed by the technical staff.

Open Item 2.3.1.6-1 (steam generator feedrings)

The staff believes that the steam generator (SG) feedrings should be included in the scope of license renewal (Open Item 2.3.1.6-1). Since this component is completely enclosed by safety-related, pressure-boundary components, it is important to show that failures of this component could not impede certain safety-related functions of the components in which it is contained (10 CFR 54.4(a)(2)).

The possibility that loose parts might be generated and that they might prevent the accomplishment of certain safety functions of the steam generator is not, by itself, sufficient to require that the feedring be included in the scope for license renewal. There must be some basis in operating experience. The NEI guidelines indicated that the hypothetical failure (the loose part scenario) need not be considered, if it has not been previously experienced.

In response to a staff request for further information in RAI 2.3.1.6-1, RNP surveyed operating history experience compiled by the World Association of Nuclear Operators (WANO) and the Institute of Nuclear Power Operations (INPO) and found that there were no recorded instances of this type of failure. They did find, however, instances wherein J-tubes were replaced, due to corrosion problems, and an instance wherein there was direct leakage for the feedring. These can be considered to be preconditions to the loose part scenario. Therefore, the staff believes that the feedring should be within the scope of license renewal.

In a letter dated September 16, 2003 (ADAMS accession no. ML032650884), the applicant agreed to include the steam generator feedrings in the scope of the license renewal application. The steam generator feedrings and their associated aging management program are discussed in Section 3.1.2.2.14 of this report. The staff reviewed the steam generator feedrings and their associated components that were subject to an AMR and found that the applicant has adequately included components of the steam generator feedrings, as required by 10 CFR 54.21(a)(1). Therefore, Open Item 2.3.3.6-1 is closed.

Open Item 2.3.3.8-1 (exclusion of deepwell pumps, piping, and valves from an AMR)

The staff requested the applicant to provide adequate justification for the exclusion of the deepwell pumps and associated piping from an AMR. The staff found that the applicant has not adequately justified the referred exclusion. The context of Section 10.4.8 of the UFSAR does not link dam failure to any particular set of initiating events, and seismic events and age-related degradation do not encompass all credible causes of dam failure. Dam failure results in loss of the ultimate heat sink and loss of the normal backup supply of feedwater from the service water system through the auxiliary feedwater system. Following dam failure and depletion of the condensate storage tank inventory, failure of the deepwell pumps would cause failure of the safety-related auxiliary feedwater system and prevent the residual heat removal (RHR) necessary to maintain a safe shutdown condition. Therefore, the deepwell pumps and associated piping are within the scope of license renewal (LR) in accordance with 10 CFR 54.4(a)(2). Therefore, the staff found that the applicant has not adequately justified excluding the deepwell pumps and associated piping and valves from an AMR, and this issue remains as Open Item 2.3.3.8-1.

By letter dated September 16, 2003, the applicant agreed to include, within the scope of license renewal, the three deepwell pumps and associated piping required to provide a backup source of water for the auxiliary feedwater system. The staff found that the applicant adequately identified components of the deepwell pumps and associated piping within the scope of license renewal, as required by 10 CFR 54.4(a)(2).

The applicant completed an AMR of the deepwell pumps and associated piping, which resulted in the identification of material/environment combinations not previously identified in the LRA for the primary and demineralized water makeup system. The applicant presented the results of the revised aging management evaluations in an update to LRA Table 2.3-14. The staff reviewed the components that were subject to an AMR and found that the applicant has adequately included components of the deepwell pumps and associated piping, as required by 10 CFR 54.21(a)(1). Therefore, Open Item 2.3.3.8-1 is closed.

1.6 Summary of Confirmatory Items

Confirmatory Items are items for which the staff and the applicant have reached a satisfactory resolution, but the resolution has not yet been formally submitted to the staff.

As a result of its review of the LRA for RNP, including additional information submitted to the NRC through April 28, 2003, the staff identified the following issues that remained confirmatory at the time this report was prepared.

Confirmatory Item 2.3.1.3-1 (pressurizer spray head)

The staff believed that the pressurizer spray head should be included in the scope of license renewal (RAI 2.3.1.3-1). Since this component is completely enclosed by safety-related, pressure-boundary components, it is important to show that its failure could not impede certain safety-related functions of the components in which they are contained (10 CFR 54.4(a)(2)). The possibility of a failure in the pressurizer spray head, affecting the functioning of the PORVs or pressurizer safety valves, was noted. The applicant surveyed operating experience and concluded that such a failure had not occurred anywhere. The applicant provided supplemental information in support of a revised response to RAI 2.3.1.3-1. Pending the applicant's formal submittal of this information and the NRC staff's review of the acceptability of the supplemental information, RAI 2.3.1.3-1 will be considered to be Confirmatory Item 2.3.1.3-1.

After reviewing the applicant's response, the staff concluded that it was not necessary to include the pressurizer spray head in the license renewal scope to meet the requirements of either 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3). Furthermore, the possibility of a failure in the pressurizer spray head, affecting the functioning of the PORVs or pressurizer safety valves, was postulated and considered under the terms of 10 CFR 54.4(a)(2). In accordance with the NEI guidelines in NEI 95-10, Revision 3, the staff requested CP&L to provide information to show that its hypothetical failure has not been experienced at RNP or at other plants. The applicant surveyed plant-specific and industry-wide operating experience and found that there were no known occurrences of the postulated failure scenario. Therefore, the staff concludes that inclusion of the pressurizer spray head in the license renewal scope is not required by 10 CFR 54.4(a)(2).

Confirmatory Item 2.3.2.5-1 (hydrogen recombiners and supporting components)

The staff considered the applicant's responses to RAIs 2.3.2.5-1, 2.3.2.5-2, and 2.3.2.5-3 to be unacceptable because they are incomplete. Although the responses provided sufficient information to demonstrate that 10 CFR 54.4(a)(1) and (a)(3) did not apply to the hydrogen recombiners and supporting components, they did not adequately demonstrate that these components were not within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). Specifically, although ample time is available to effect hydrogen control, 10 CFR 54.4 does not explicitly permit components required for accident mitigation to be excluded from the scope of license renewal on that basis. In addition, although the response states that sufficient time exists to ensure that all components of the recombiner system are operable before its operation is required, UFSAR Section 6.2.5.2.2 indicates that the majority of the lines associated with this system cannot be repaired due to the high radiation rates present during post accident conditions. As described further in Section 2.3.2.5.2 of this SER, the applicant has transmitted a revised draft response to these RAIs that would bring within scope the components of the hydrogen recombiner system that are necessary to fulfill the hydrogen control intended function. Pending the applicant's formal submittal of this information and the NRC staff's review of the acceptability of the aging management results for the components that would be added within scope, RAIs 2.3.2.5-1, 2.3.2.5-2, and 2.3.2.5-3 are considered to be Confirmatory Item 2.3.2.5-1.

By a letter dated September 16, 2003, the applicant transmitted a revised response to these items that would bring within scope the components of the hydrogen recombiner system that are necessary to fulfill the hydrogen control intended function. Specifically, in addition to the components necessary for containment isolation, the response brings within scope the hydrogen recombiner, permanently installed piping, and temporary flexible piping associated with the post-accident hydrogen system pressure boundary, as well as the passive pressure boundary components of the associated nitrogen system that actuates the containment isolation valves which would permit the flow of containment atmosphere to and from the hydrogen recombiner. Based on the applicant's decision to bring those components within scope of license renewal the staff finds the applicant's responses to RAIs 2.3.2.5-1, 2.3.2.5-2, and 2.3.2.5-3 acceptable, and Confirmatory Item 2.3.2.5-3 is closed.

Confirmatory Item 2.3.3.9-1 (issued with regard to the exclusion from an AMR of the refueling water purification pump, piping, and valves necessary for spent fuel pool (SFP) makeup from the refueling water storage tank)

In discussions regarding the provision of makeup water to the spent fuel pool following loss of cooling, the applicant agreed to include components along the flow path from the refueling water storage tank (RWST) to the spent fuel pool within the scope of license renewal. The applicant indicated that a revised drawing highlighting the additional components added to the scope of license renewal and a revised list of components (including the purification pump casing, demineralizer vessel, and filter housing) that are subject to an AMR and the associated AMP would be transmitted by letter. This is Confirmatory item 2.3.3.9-1.

By letter dated August 14, 2003, the applicant formally agreed to include the SFP makeup path from the RWST to the SFP within the scope of license renewal, and described the specific boundaries of the components within the scope of license renewal. As a result of the expansion of the evaluation boundary, the applicant revised LRA Table 2.3-15 to include the SFP cooling demineralizer, SFP filter, and refueling water purification pump. The remainder of the piping components fell within existing commodity groups in LRA Table 2.3-15. The staff found that the formal description of the components subject to an AMR was consistent with the previous communication. Therefore, Confirmatory Item 2.3.3.9-1 has been resolved.

Confirmatory Item 3.0.3.2.2-1 (commitment inspections for the steam generator upper shell-to-transition cone weld)

The purpose of this item is to confirm that CP&L will commit to performing augmented inspections of the steam generator upper shell-to-transition cone weld during the two 10-year inservice inspection (ISI) intervals for the extended period of operation for RNP.

In a letter dated September 16, 2003, the applicant provided the following response to Confirmatory Item 3.0.3.2.2-1:

> RNP will continue to perform examinations of the steam generator transition girth welds as required by ASME Section XI during the period of extended operation.

The applicant's response to Confirmatory Item 3.0.3.2.2-1 confirms that the applicant will continue to perform the required ultrasonic examinations of the steam generator shell-to-transition cone girth welds during the two 10-year ISI intervals that are scheduled for the extended period of operation. This resolves Confirmatory Item 3.0.3.2.2-1 and Confirmatory Item 3.0.3.2.2-1 is closed.

Confirmatory Item 3.1.2.1-1, Parts 1 and 2 (issued with regard to the staff's assessment of AMR Item No. 22 of LRA Table 3.1-1, as evaluated in Section 3.1.2.1 of the SER)

The staff seeks confirmation as to whether or not there is any plant-specific or generic industry experience that supports the conclusion that crack initiation and growth due to stress corrosion cracking (SCC) is an applicable aging effect for carbon steel bolting materials in the reactor coolant system (RCS). If industry experience does support that crack initiation and growth due to SCC is an applicable aging effect for carbon steel bolting, the applicant should propose an AMP to manage this effect. This is Confirmatory Item 3.1.2.1-1, Part 1.

The applicant's response to RAI 3.1.2.1-3 states that stress relaxation is not applicable to valve closure bolting in the reactor coolant pressure boundary (RCPB) (i.e., RCPB valve bolting) and "other closure bolting in high pressure and high temperature systems." However, the applicant's discussion for AMR 22 to LRA Table 3.1-1 states that the Bolting Integrity Program is applicable to all RCPB bolting except reactor vessel studs for which the Reactor Head Closure Studs Program applies, and that the Bolting Integrity Program relies on the ASME Section XI, Subsection IWB, IWC, and IWD Program to assure that aging effects associated with wear and stress relaxation are managed for RCS Class 1 closure bolting and for Class 2 bolting greater than 2 inches in diameter. The applicant's discussion of AMR 22 in LRA Table 3.1-1 did not indicate that the applicant was exempting stress relaxation as an applicable aging effect for the RCPB valve bolting or "other closure bolting in high pressure and high temperature systems." Therefore, the staff concludes that the applicant's response to RAI 3.1.2.1-3, as it pertains to the management of stress relaxation in the RCPB valve bolting or "other closure bolting in high pressure and high temperature systems," contradicts the applicant's discussion of AMR 22 in LRA Table 3.1-1. The staff requests confirmation that, other than SCC, the aging effects identified in AMR 22 to LRA Table 3.1-1 are still applicable to the RCS bolting within the scope of the commodity group, other than the steam generator primary and secondary manway and handhole bolting. The applicant must explain the contradiction in the RAI response and the information in AMR 22 of LRA Table 3.1-1. This is Confirmatory Item 3.1.2.1-1, Part 2.

In a letter dated September 16, 2003, the applicant provided the following response to Confirmatory Item 3.1.2.1-1, Part 1:

> The RNP Aging Management Review (AMR) has not identified plant-specific or generic industry experience which supports a conclusion that crack initiation and growth due to Stress Corrosion Cracking (SCC) is an applicable aging effect for carbon steel or low-

alloy steel bolting materials in the reactor coolant system (RCS). This is supported by operating experience and existing data which indicate that SCC failure should not be a significant issue for closure bolting within the RCS.

The applicant's response to Confirmatory Item 3.1.2.1-1, Part 1, confirms that there has not yet been any RNP-specific or generic operating experience to support the conclusion that SCC-induced cracking is an aging issue for carbon steel bolting materials in ASME Class 1 systems. The staff therefore concludes that SCC-induced cracking is not an aging effect requiring aging management for ASME Class 1 carbon steel bolting made from carbon steel materials. The staff therefore considers Confirmatory Item 3.1.2.1-1, Part 1, to be resolved, and Confirmatory Item 3.1.2.1-1, Part 1, is closed.

In the applicant's response to Confirmatory Item 3.1.2.1-1, Part 2, dated September 16, 2003, the applicant explained their response to RAI 3.1.2.1-3 and confirmed that loss of preload due to stress relaxation is an applicable aging effect requiring aging management for the RCS bolting materials within the scope of AMR 22 in LRA Table 3.1-1. The staff therefore considers Confirmatory Item 3.1.2.1-1, Part 2, to be resolved, and Confirmatory Item 3.1.2.1-1, Part 2 is closed.

Confirmatory Item 3.1.2.1-1, Part 3 (issued with regard to the staff's assessment of AMR Item No. 22 of LRA Table 3.1-1, as evaluated in Section 3.1.2.1 of the SER)

In its response to RAI 3.1.2.1-3, the applicant stated that it recognizes that stress relaxation can occur in the SG manway and handhole bolting, at least for the bolting on the secondary side of the SGs, and stated that it has a bolting and torque program to determine the closure and torque requirements for RCS closure bolting. However, in its response to RAI 3.1.2.1-3, the applicant did not identify loss of preload as an aging effect and did not identify an AMP to manage the aging effect associated with SG bolting. GALL IV.D.1.1.7 identifies that loss of pre load due to stress relaxation is an aging effect for the steam generator secondary manway and handhole bolting, and GALL XI.M18, "Bolting Integrity," is the AMP to manage this aging effect. According to 10 CFR 54.21(1), license renewal applicants must perform AMRs and identify all applicable aging effects for passive components within the scope of license renewal. The SG primary and secondary manway and handhole bolts are passive components within the scope of license renewal. The applicant has stated that stress relaxation is an applicable aging effect for the SG secondary manway and handhole bolting; therefore, the applicant is required by 10 CFR 54.21(a)(3) to propose an AMP to manage the aging effect. The staff also requests the applicant to provide technical justification as to why loss of preload stress relaxation does not have to be managed for the primary SG manway bolts in the manner required for the management of the SG secondary side bolting. In subsequent discussions with the NRC staff to resolve this issue, the applicant stated that the RNP Bolting Integrity Program in LRA Section B.3.4 will be applied to the pressure retaining bolting for the primary and secondary side of the steam generators because the RNP Bolting Integrity Program can be relied upon to prevent the loss of preload and that the RNP Bolting Integrity Program will not take exception to the Scope of Program in GALL XI.M18, "Bolting Integrity." The staff evaluates the RNP Bolting Integrity Program in Section 3.0.3 of this SER. The staff finds the applicant's resolution of the issue acceptable because the applicant credits its Bolting Integrity Program to manage loss of preload due to stress relaxation in the SG primary and secondary manway and handhole bolts. However, the applicant needs to submit its resolution under oath and affirmation; therefore, this is Confirmatory Item 3.1.2.1-1, Part 3.

In its response to Confirmatory Item 3.1.2.1-1, Part 3, dated September 16, 2003, the applicant stated that the RNP Bolting Integrity Program is applied to pressure retaining bolting for the primary and secondary side of the steam generator. The applicant modified the Bolting Integrity Program to include the aging management of the SG primary and secondary bolting. As specified in LRA section B.3.4, "Bolting Integrity Program," loss of preload due to stress relaxation is one of the aging effects that will be managed. The staff's evaluation of the applicant's Bolting Integrity Program is discussed in Section 3.0.3.6 of this SER. The staff concludes that Confirmatory Item 3.1.2.1-1, Part 3, is closed because the applicant's Bolting Integrity Program will adequately manage the aging effect of loss of preload due to stress relaxation in the steam generator primary and secondary side bolting.

Confirmatory Item 3.1.2.1-2 (issued with regard to the staff's assessment of AMR Item No. 26 of LRA Table 3.1-1, as evaluated in Section 3.1.2.1 of the SER)

In order to provide reasonable assurance that general corrosion is not an applicable aging effect for the Class 1 carbon steel or low-alloy steel components in containment air or indoor air environments, the staff seeks confirmation that the Class 1 carbon steel or lower alloy steel components operate at temperatures that are equivalent to or hotter than the ambient temperature for the surrounding containment air or indoor air environments. This is Confirmatory Item 3.1.2.1-2.

The applicant provided the following response to Confirmatory Item 3.1.2.1-2 in a letter dated September 16, 2003:

> RNP confirms that Class 1 carbon steel or low alloy steel components operate at temperatures that are equivalent to or hotter than the ambient temperature for the surrounding containment air or indoor air environments.

The applicant's response to Confirmatory Item 3.1.2.1-2 confirms that the Class 1 carbon steel or low-alloy steel components in the RCS operate at temperatures equivalent to or hotter than the ambient temperatures for their external atmospheric environments (i.e., the containment air or indoor air environments). Based on the applicant's response, the staff concludes that precipitation on the components therefore will not be a concern for the extended period of operation for RNP and that general corrosion induced by precipitation on the Class 1 carbon steel or low-alloy steel components is not an aging effect requiring aging management during the extended period of operation for RNP. Confirmatory Item 3.1.2.1-2 is therefore resolved, and Confirmatory Item 3.1.2.1-2 is closed.

Confirmatory Item 3.1.2.1-3, Parts 1 and 2 (issued with regard to the staff's assessment of AMR Item No. 31 of LRA Table 3.1-1, as evaluated in Section 3.1.2.1 of the SER)

The staff seeks confirmation that the reactor vessel (RV) thermal shield is adjacent to the fuel zone region of the RV, receives a neutron fluence greater than $1x10^{17}$ n/cm2, is within the scope of the commodity group in AMR 31 to LRA Table 3.1-1, and will be managed by the Pressurized Water Reactor Internal Program. This is Confirmatory Item 3.1.2.1-3, Part 1.

The staff seeks confirmation whether or not the RV internal lower support and lower support plate columns are fabricated from cast austenitic stainless steel (CASS) materials and are within the scope of AMR Item 8 of LRA Table 3.1-1, AMR Item 33 of LRA Table 3.1-1, and AMR Item 14 of LRA Table 3.1-2. This is Confirmatory Item 3.1.2.1-3, Part 2.

The applicant's response to RAI 3.1.2.1-9, Part 1, as amended by the applicant's response to Confirmatory Item 3.1.2.1-3, Part 1, also provides an acceptable basis for omitting the RNP thermal shield from the scope of AMR Item 31 of LRA Table 3.1-1, because the applicant has committed to continued participation in the EPRI-MRP's activities for investigating the aging effects that are applicable to the pressurized-water reactor (PWR) internals of PWR-designed light-water reactors, and to use its participation in the activities as the basis for developing its inspection plan for the PWR Vessel Internals Program. This will include industry initiatives to study the aging effects that are applicable to the thermal shields of PWR-designed light-water reactors and to determine whether nondestructive inspections are warranted for the thermal shields and, if warranted, which inspection methods are most appropriate for the examinations. The applicant has also committed to submitting its inspection plan for the PWR Vessel Internals Program to the staff for review and approval 24 months prior to its implementation. These commitments are given in Commitment No. 33 of Attachment II of CP&L Serial Letter No. RNP-RA/03-0031, dated April 28, 2003. The staff considers that this commitment will permit the staff an opportunity to determine and resolve with the applicant whether additional inspections are warranted for the RNP RV internals, including the thermal shield. The staff therefore considers RAI 3.1.2.1-9, Part 1, and Confirmatory Item 3.1.2.1-3, Part 1, to be resolved and RAI 3.1.2.1-9, Part 1, and Confirmatory Item 3.1.2.1-3, Part 1, are closed.

The applicant provided its response to Confirmatory Item 3.1.2.1-3, Part 2, in a letter dated September 16, 2003. In this response, the applicant clarified that only the upper support tube base, lower support plate columns, and bottom-mounted instrumentation column cruciform are fabricated from CASS. The applicant clarified that the lower support column forging is fabricated from austenitic stainless steel and that the AMRs for this forging are given in AMR Items 8 and 33 of LRA Table 3.1-1. The applicant confirmed that the lower support forging is not within the scope of AMR Item 14 of LRA Table 3.1-2 because the component is not fabricated from CASS. Since the applicant has provided the clarifications requested by the staff relative to the CASS RV internal components, the staff considers Confirmatory Item 3.1.2.1-3, Part 2, to be resolved, and Confirmatory Item 3.1.2.1-3, Part 2 is closed.

Confirmatory Item 3.1.2.2.4-1 (issued with regard to the staff's assessment of AMR Item No. 6 of LRA Table 3.1-1, as evaluated in Section 3.1.2.2.4 of the SER)

The staff is concerned that the AMPs credited by the applicant for managing crack initiation and growth of small bore Class 1 piping may be used as a precedent for relieving the applicant of performing the required ASME ISI examinations for the small bore Class 1 piping welds during the period of extended operation for RNP. Therefore, the staff seeks confirmation that the applicant will continue to perform the ISI examinations of the small bore Class 1 piping that are required by Section XI of the ASME Boiler and Pressure Vessel Code during the period of extended operation for RNP.

In its response to Confirmatory Item 3.1.2.2.4-1, dated August 14, 2003, the applicant confirmed that it would continue to conduct all applicable ISI inspections of the Class 1 small bore piping required by Section XI of the ASME Boiler and Pressure Vessel Code, unless relief is requested from and granted by the staff under applicable provisions in 10 CFR 50.55a.

Since the applicant response indicates that the applicant will continue to meet the inspection requirements for Class 1 small bore pipe, as required by 10 CFR 50.55a and Section XI of the ASME Boiler and Pressure Vessel Code, during the period of extended operation for RNP, the applicant's response to Confirmatory Item 3.1.2.2.4-1 is acceptable. Confirmatory Item 3.1.2.2.4-1 is resolved.

Confirmatory Item 3.1.2.2.7-1 (issued with regard to the staff's assessment of AMR Item No. 9 of LRA Table 3.1-1, as evaluated in Section 3.1.2.2.7 of the SER)

The staff seeks confirmation that the welds used to join the SG instrumentation nozzles to the SG shells were fabricated using Alloy 600 weld material (i.e., Alloy 82/182 filler metals). If Alloy 600 weld materials are utilized, the applicant should discuss whether the welds are within the scope of and managed by the Nickel-Alloy Nozzles and Penetrations Program. This is Confirmatory Item 3.1.2.2.7-1.

In its response to Confirmatory Item 3.1.2.2.7-1, dated September 16, 2003, the applicant stated that the welds joining the carbon steel steam generator shell to the carbon steel instrumentation nozzles are not fabricated from Alloy 600 weld material. The staff finds that the Nickel-Alloy Nozzles and Penetrations Program would not be an appropriate AMP to manage the aging effects of the instrumentation nozzle welds because Alloy 600 materials (i.e., Alloy 82/182 filler metals) are not used in the welds. However, the steam generator instrumentation nozzles and associated welds are being managed by other applicable AMPs as discussed above. The staff concludes that Confirmatory Item 3.1.2.2.7-1 is closed because the applicant has clarified that the welds joining the carbon steel steam generator shell to the carbon steel instrumentation nozzles are not made of Alloy 600 materials.

Confirmatory Item 3.1.2.4.4.3-1 (issued with regard to the staff's assessment of AMR Item No. 10 to LRA Table 3.1-2, as evaluated in Section 3.1.2.4.4.3 of the SER)

The staff seeks confirmation that CP&L is crediting the Nickel-Alloy Nozzles and Penetrations Program as an additional AMP for managing primary water stress corrosion cracking (PWSCC) in the RNP bottom head instrumentation tube nozzles. This is Confirmatory Item 3.1.2.4.4.3-1.

The applicant provided the following response to Confirmatory Item 3.1.2.4.4.3-1 by letter dated September 16, 2003. RNP will maintain its involvement in industry initiatives and will implement any actions, unless impracticable, that are agreed upon between the NRC and the nuclear power industry to monitor for, detect, evaluate, and correct cracking in the VHP nozzles, specifically as the actions relate to ensuring the integrity of VHP nozzles in the RNP upper reactor vessel head during the extended period of operation. RNP also agreed to submit, for review and approval, its inspection plan for the Nickel-Alloy Nozzles and Penetrations Program, as it will be implemented from participation in industry initiatives prior to July 31, 2009.

Based on the applicant's response to Confirmatory Item 3.1.2.4.4.3-1, the applicant's commitment to Commitment # 31 to attach the CP&L's serial letter No. RNP-RA/03-0031 and the clarification provided in the applicant's response to RAI 3.1.2.4.4-1 and B.4.1-1, the staff concludes that the applicant has provided an acceptable method of determining which inspection methods will be necessary for the RNP bottom head instrumentation tube nozzles during the extended period of operation for RNP, as determined from the industry's initiatives on managing degradation of nickel-based alloy components and welds, the state of pertinent industry operating experience (OE) on degradation of PWR bottom head instrumentation tube nozzles (including that for STP), and the staff's resolution of this OE with licensed utilities in the industry. Confirmatory Item 3.1.2.4.4.3-1 is resolved.

Confirmatory Item 3.1.2.4.5.2-1 (issued with regard to the staff's assessment of AMR Item No. 9 to LRA Table 3.1-2, as evaluated in Section 3.1.2.4.5.2 of the SER)

The staff seeks confirmation that CP&L is crediting the Nickel-Alloy Nozzles and Penetrations Program as an additional AMP for managing PWSCC in the RV core support pads. This is Confirmatory Item 3.1.2.4.5.2-1.

The applicant provided the following response to Confirmatory Item 3.1.2.4.5.2-1 by letter dated September 16, 2003. RNP will maintain its involvement in industry initiatives and will implement any actions, unless impracticable, that are agreed upon between the NRC and the nuclear power industry to monitor for, detect, evaluate, and correct cracking in the VHP nozzles, specifically as the actions relate to ensuring the integrity of VHP nozzles in the RNP upper reactor vessel head during the extended period of operation. RNP also agreed to submit, for review and approval, its inspection plan for the Nickel-Alloy Nozzles and Penetrations Program, as it will be implemented from participation in industry initiatives prior to July 31, 2009.

Based on the applicant's response to Confirmatory Item 3.1.2.4.5.2-1, the applicant's commitment to Commitment # 31 to attach the CP&L's serial letter No. RNP-RA/03-0031 and the clarification provided in the applicant's response to RAI 3.1.2.4.4-1 and B.4.1-1, the staff concludes that the applicant has provided an acceptable method of determining which inspection methods will be necessary, if any, for the RNP RV core support pads during the extended period of operation for RNP, as determined from the applicant's commitment to maintain its continued participation in the industry's initiatives on nickel-based alloy components and welds and its commitment to submit the Nickel-Alloy Nozzles and Penetrations Program to the staff for review and approval. Confirmatory Item 3.1.2.4.5.2-1 is resolved.

Confirmatory Item 3.1.2.4.5.5-1 (nickel-based alloy in-core flux thimble tubes)

The staff seeks confirmation that the scope of AMR Item 16 of LRA Table 3.1-2 is for nickel-based alloy in-core flux thimble tubes and not for the retractable in-core flux thimbles. An inspection-based program should be used in conjunction with the Water Chemistry Program to manage SCC in these components. Therefore, the staff also seeks confirmation that the applicant will credit both the PWR Vessel Internals Program and the Water Chemistry Program to manage SCC (including PWSCC and/or irradiation-assisted stress-corrosion cracking (IASCC)) in the nickel-based alloy in-core flux thimble tubes. This is Confirmatory Item 3.1.2.4.5.5-1.

In response to this confirmatory item, the applicant revised Commitment No. 31 on the Nickel-Alloy Nozzles and Penetrations Program. This revision was submitted to the NRC by the CP&L Serial Letter No. RNP-RA/03-0154, dated December 10, 2003. This version of the commitment included a commitment to: (1) participate in the MRP's industry initiatives on cracking of nickel-based alloy components, (2) implement those recommendations that result for the MRP's studies on these matters and are acceptable to the NRC, and (3) to submit the inspection plan for the Nickel-Alloy Nozzles and Penetrations Program for NRC review and approval by July 31, 2009. The commitment to submit the Nickel-Alloy Nozzles and Penetrations Program for staff review and approval will provide a sufficient opportunity to determine whether cracking is an issue for the Alloy 600 thimble outer sheaths that are exposed to the reactor coolant and to discuss with the applicant whether inspections of the components will be needed during the extended period of operation for RNP. The staff therefore concludes that this is an acceptable process for managing cracking that may potentially occur in the thimble outer sheaths. Based on this assessment, the staff concludes that the applicant has proposed an acceptable basis for managing cracking in the flux thimbles at RNP and that AMR 16 of LRA Table 3.1-2 is acceptable. Therefore, Confirmatory Item 3.1.2.4.5.5-1 is resolved.

Confirmatory Item 3.3.2.3.3-1 (confirmation that the diesel- and motor-driven fire pumps are overhauled on a 10-year cycle, and this overhaul includes inspection of the bowls)

During the AMR inspection (June 9–13, 2003), the staff reviewed the applicant's replacement frequency for fire pump casings for the Fire Protection Program (see LRA Table 3.3-2, Item 30). The audit noted that there is an error in the application and the fire pumps do not have casings, rather the vertical shaft pumps used at RNP use bowls for the pressure boundary function. Furthermore, the inspection indicated that these bowls are not replaced on a 10 year cycle, rather the pumps are overhauled on a 10-year cycle. Overhaul does not specifically require replacement of the bowls. The applicant explained during a phone call on June 12, 2003, that the frequency of the overhaul of the fire pumps is consistent with OE and that the current Preventive Maintenance Program is effective at ensuring the pumps remain operable during a 10-year service between overhauls. A Confirmatory Item 3.3.2.3.3-1 will be included for the applicant to confirm that the diesel- and motor-driven fire pumps are overhauled on a 10-year cycle and this overhaul includes inspection of the bowls (i.e., the pressure retaining portion of the pump), and the bowls may or may not be replaced based upon their condition.

In its response dated September 16, 2003, the applicant included a revision of LRA Table 3.3-2, Item 30. This revision corrected the language to reference bowls rather than casings. The same letter also corrected the discussion to state that the diesel- and motor-driven fire pumps are overhauled on a 10-year cycle, and this overhaul includes inspection of the bowls. This is a change from the previous language which stated that the bowls are replaced on a 10-year frequency. The applicant has determined that based on OE this frequency is adequate to manage aging-related degradation. The staff found the applicant's response to be acceptable, and Confirmatory Item 3.3.2.3.3-1 is considered to be closed.

Confirmatory Item 3.3.2.4.7-1 (AMP of radioactive equipment drains)

This confirmatory item relates to radioactive equipment drain system (REDS). In RAI 2.3.3.7-2, the staff requested the applicant to clarify which portions of this system are included within the scope of license renewal and subjected to an AMR. In its response dated April 28, 2003, the applicant described the portions of the REDs that are within the scope of license renewal and identified the aging effect of loss of material due to crevice corrosion, pitting corrosion, and microbiologically induced corrosion (MIC). In its response to RAI 2.3.3.7-2, the applicant stated that the identified aging effects do not affect the intended function of the REDS and, therefore, do not require management for the period of extended operation. Based on the information provided in the LRA and the additional information included in the applicant's response to RAI

2.3.3.7-2, the staff requested the applicant to provide additional information to support its conclusion that the identified aging effects do not affect the intended function of the REDS and, therefore, do not require management for the period of extended operation. On June 17, 2003, in a telephone conference, the staff discussed the issue further with the applicant. Subsequent to the telephone conference, by an electronic correspondence dated June 19, 2003, the applicant provided information to support its conclusion on the aging management of REDS. This explanation has been discussed in Section 3.3.2.4.7.2 of this SER. The staff finds that the applicant has provided adequate information to justify that no AMP is required to manage the aging effects of the REDS because the applicant has demonstrated that leaking and blockage of the REDS are unlikely, the potential flow blockage will be identified and corrected timely by the applicant's routine inspection and other activities, and leakage of the REDS would not adversely impact the performance of the SSCs. However, the applicant was requested to clarify the applicable aging effects for these REDs components and to incorporate the supporting explanation as discussed above into its response to RAI 2.3.3.7-2. This is Confirmatory Item 3.3.2.4.7-1.

By letter dated August 14, 2003, the applicant provided the requested information. Based on its review of the information provided in the LRA and the additional information provided in the applicant's response to RAI 3.3.2.4.7-1, the staff concurs with the applicant's conclusion that no AMP is required to manage the aging effects of the REDS and that there is reasonable assurance that the intended functions of the REDS will remain. Therefore, Confirmatory Item 3.3.2.4.7-1 is resolved.

Confirmatory Item 3.3.2.4.17-1 (aging effects for the components in the dedicated shutdown diesel generator)

This confirmatory item relates to the aging effects for the materials and environments associated with the components in the dedicated shutdown diesel generator. In RAI 3.3.17-1, the staff requested the applicant to provide a detailed discussion on the AMR performed for the stainless steel valves, piping, tubing, and fittings listed in Table 3.3-2, row numbers 12, 13, and 23, and explain why the AMR results are different among them. In its response, the applicant stated that the air and gas environments in row numbers 12 and 13 include the potential for wetting of stainless steel by untreated water, which is the genesis of the potential aging effects. A detailed explanation of the response has been included in Section 3.3.2.4.17 of this SER. The staff found the referenced explanation appropriate. However, the applicant is requested to provide the above information under oath and affirmation, and this remains as Confirmatory Item 3.3.2.4.17-1.

By letter dated August 14, 2003, the applicant provided the requested information. On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to RAIs 3.3-3 and 3.3-5, the staff finds that the aging effects that result from contact of the dedicated shutdown (DS) diesel generator (DG) SSCs to the environments described in Tables 2.3-23, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the DS DG. Confirmatory Item 3.3.2.4.17-1 is resolved.

Confirmatory Item 3.3.2.4.19-1 (aging effects for the components in the fuel oil system)

This confirmatory item relates to the aging effects for the materials and environments associated with the components in the fuel oil system. In RAI 3.3.17-1, the staff requested the applicant to provide a detailed discussion of the AMR performed for the stainless steel valves, piping, tubing, and fittings listed in Table 3.3-2, row numbers 12, 13, and 23, and explain why the AMR results are different among them. The air and gas environments in row numbers 12 and 13 include the potential for wetting of stainless steel by untreated water, which is the genesis of the potential aging effects. In row number 23, the environment is considered a reasonably dry environment which results in no potential aging effects for stainless steel. For the fuel oil system, it has a stainless steel valve and instrumentation tubing, valves, and fittings that are conservatively modeled in a wetted outdoors environment. The fuel oil tank level instrumentation is located outdoors and has components that are near the ground. A detailed explanation of the response has been included in Section 3.3.3.4.19 of this SER. The staff found the referenced explanation appropriate. However, the applicant is requested to provide the above information under oath and affirmation, and this remains as Confirmatory Item 3.3.24.19-1.

The applicant has provided additional information related to the aging effects of the external surfaces of the SS components/environments combination in the response to Confirmatory Item 3.3.2.4.19-1, in letter RNP-RA/03-0094, dated August 14, 2003. The staff found the applicant's response to be acceptable. Therefore, Confirmatory Item 3.3.2.4.19-1 is resolved.

Confirmatory Item 3.5-1 (AMP for below-grade reinforced concrete)

In RAI 3.5.1-3, the staff requested the applicant to provide available RNP ground-water chemistry test results including chlorides, sulphate, and pH values and discuss the proposed AMP, as well as past inspection results of below-grade concrete at RNP, since the below-grade reinforced concrete at RNP is exposed to an aggressive environment (low pH). In RAI 3.5.1-9 the staff stated that it is unclear how the inspection for below-grade containment concrete will be performed by the ASME Section XI, Subsection IWL Program and requested that additional information, such as the locations, depth, and frequency of soil excavation, related to the AMR of below-grade containment concrete be provided. The applicant responded to both RAIs offering commitments that adequately address the staff concerns regarding the aging management of below-grade in-scope concrete structural components at RNP. Because of the slightly acidic RNP ground-water environment, the applicant conservatively assumed existence of an aggressive chemical environment and proposed the plant-specific AMPs (an enhanced ASME, Section XI, Subsection IWL Program for containment and an enhanced Structures Monitoring Program for other Category 1 structures) described in Section 3.5.2.2.1.1 of this SER to manage the aging effects of below-grade concrete. The staff finds RAIs 3.5.1-3 and 3.5.1-9 are fully resolved, pending satisfactory resolution of Confirmatory Item 3.5-1.

By letter dated August 14, 2003 (RNP Serial RNP-RA/03-0094), the applicant responded to a number of confirmatory items identified by the staff. The staff reviewed the revised contents of Items 25, 26, and 27 of Attachment II (Revised License Renewal Commitments). The staff also reviewed the specific response to Confirmatory Item 3.5-1 provided in Attachment III (Response to License Renewal Confirmatory Items) in the same letter. Based on these reviews, the staff finds that the applicant has provided adequate information, and Confirmatory Item 3.5-1 is closed.

Confirmatory Item 3.6.2.3.1.2-1 (non-EQ insulated cables and connections program)

In LRA Section B.4.6, "Non-EQ Insulated Cables and Connections Program," the applicant described its AMP to manage aging in non-EQ insulated cables and connections. The LRA stated that this AMP is consistent with GALL AMPs XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," with no deviations. In response to the staff's concern (RAI B.4.6-2) about excluding non-polyvinyl chloride (PVC) cables inside and outside containment in an adverse localized environment from the sample, the applicant in a letter dated June 13, 2003, stated that the scope of this program includes plant cables and connections of various insulation material types (not just PVC) that may be located in an adverse, localized environment. On the basis of its review, the staff finds that its concern is not resolved. In subsequent discussions with the NRC staff to resolve this issue, the applicant stated that the statement in LRA Section B.4.6 regarding "The sample locations will consider the location of PVC cables inside and outside containment as well as any known adverse localized environments, (PVC was determined to be the limiting insulation material)" will be modified by "The sample locations will consider the location of cables and connections inside and outside containment as well as any known adverse localized environments." The staff finds that the applicant's resolution of this issue is acceptable because the sample will consider all insulation material types used inside and outside containment as well as any known adverse localized environments. However, the applicant needs to submit its resolution under oath and affirmation; therefore, this is Confirmatory Item 3.6.2.3.1.2-1

In its response dated September 16, 2003, the applicant revised the LRA Section B.4.6 to read, "The sample locations will consider the location of cables and connections inside and outside containment as well as any known adverse localized environments." The staff found the applicant's response to be acceptable, and Confirmatory Item 3.6.2.3.1.2-1 is considered to be closed.

Confirmatory Item 3.6.2.3.2.2-1 (AMP for non-EQ electrical cables used in instrumentation circuits (B.4.7))

For the GALL attribute, "Operating Experience," the applicant stated that changes in instrument calibration data can be caused by degradation of the circuit cable and are a possible indication of potential cable degradation. The staff finds that the applicant did not address the operating experience in the formal response. In subsequent discussions with the NRC staff to resolve this issue, the applicant stated that this element will be revised to address the operating experience as follows. Industry operating experience indicates that changes in instrument calibration data can be caused by degradation of the circuit cable and are a possible indication of potential cable degradation. This program is for the non-EQ portions of the high range radiation monitoring cabling systems. These cabling systems are located in non harsh environments and none have experienced age-related degradation. The staff finds that the applicant's resolution of the open item is acceptable because the applicant adequately addressed the operating experience. However, the applicant needs to submit its resolution under oath and affirmation; therefore, this is Confirmatory Item 3.6.2.3.2.2-1.

In its response dated September 16, 2003, the applicant revised the operating experience to include the following, "Industry operating experience indicates that changes in instrument calibration data can be caused by degradation of the circuit cable and are a possible indication of potential cable degradation. This program is for the non-EQ portions of the high range radiation monitoring cabling systems. These cabling systems are located in non harsh environments and none have experienced age related degradation." The staff found the applicant's response to be acceptable, and Confirmatory Item 3.6.2.3.2.2-1 is considered to be closed.

Confirmatory Item 3.6.2.3.2.2-2 (AMP for neutron flux instrumentation (B.4.8))

To detect aging effects, the cables used in neutron flux instrumentation circuits will be tested at least once every 10 years. Testing may include insulation resistance tests, TDR tests, I/V testing, or other testing judged to be effective in determining cable insulation condition. Following issuance of a renewed operating license for RNP, the initial test will be completed before the end of the initial 40-year license term for Unit 2 (July 31, 2010). The staff finds that this testing is acceptable because the testing will determine cable insulation resistance (potential degradation); however, the staff is concerned about the 10-year testing frequency. In subsequent discussions with the NRC staff to resolve this issue, the applicant stated that a review of site operating experience found no age-related failures for neutron monitoring cables or connectors. The only industry operating experience identified for these cables was Westinghouse Technical Bulletin 86-01. This bulletin identified industry concerns with cables used for the source range detector regarding cable degradation due to high operating voltage, radiation, heat, and moisture. Both the source range and intermediate range detector cables inside containment were replaced in 1991 as a result of that bulletin. These cables had operated for 20 years without failure prior to being replaced. The replacement cables were manufactured to Class 1E standards and have remained functional during the last 12 years. The power range cables are the original installed cables and are the same cable type (Amphenol/Essex 21-529) that was originally used in the source range and intermediate range circuits. They have operated for over 32 years without failure, which demonstrates their ability to operate over long periods without a loss of intended function..

In addition, the licensee stated that initial testing of all in-scope neutron monitoring cables will be performed prior to the end of the current license term. This testing will provide a positive means of detecting any significant aging that has occurred since the cables were installed, which in the case of the power range cables will be after 33—40 years of operation. Given the operating experience of these cables and the gradual nature of cable insulation aging, the 10-year testing frequency subsequent to the initial testing provides reasonable assurance that the cables will continue to perform their intended function. The staff finds that the applicant's resolution of the issue is acceptable because the cable insulation degradation is a slow process and RNP operating experience did not identify any cable insulation degradation. Additionally, this 10-year frequency is consistent with NUREG-1801 cable aging management programs frequency. However, the applicant needs to submit its resolution under oath and affirmation; therefore, this is Confirmatory Item 3.6.2.3.2.2-2.

In response to the above confirmatory item, the applicant, in a letter dated September 16, 2003, stated the following:

> A review of site operating experience found no age related failures for neutron monitoring cables or connectors. The only industry operating experience identified for these cables was Westinghouse Technical Bulletin 86-01. This Bulletin identified industry concerns with cables used for the source range detector regarding cable degradation due to high operating voltage, radiation, heat, and moisture. Both the source range and intermediate range detector cables inside containment were replaced in 1991 as a result of that bulletin. These cables had operated for 20 years without failure prior to being replaced. The replacement cables were manufactured to Class 1E standards and have remained functional during the last twelve years. The power range cables are the original installed cables and are the same cable type (Amphenol/Essex 21-529) that was originally used in the source range and intermediate range circuits. They have operated for over 32 years without failure, which demonstrates their ability to operate over long periods without a loss of intended function.

In addition, the licensee stated that the following:

> Initial testing of all in-scope neutron monitoring cables will be performed prior to the end of the current license term. This testing will provide a positive means of detecting any significant aging that has occurred since the cables were installed, which in the case of the power range cables will be after 33—40 years of operation. Given the operating experience of these cables and the gradual nature of cable insulation aging, the 10 year testing frequency subsequent to the initial testing provides reasonable assurance that the cables will continue to perform their intended function.

In addition, the applicant modified the operating experience element as described in Section 3.6.2.3.2. The staff found the applicant's response to be acceptable, and on such basis Confirmatory Item 3.6.2.3.2.2-2 is considered to be closed.

Confirmatory Item 4.2.3-1 (update of UFSAR Supplement in accordance with the reference temperature $(RT)_{PTS}$ and upper-shelf energy (USE) values listed in WCAP-15828)

The staff requests confirmation that, at the next update of the UFSAR Supplement for RNP, the applicant will update Sections A.3.2.1.1 and A.3.2.1.2 of Appendix A in the LRA to reference the applicability of PTS and USE analyses in WCAP-15828, Revision 0, to the 60-year PTS and USE assessments for the RNP RV beltline materials and will update the corresponding UFSAR Supplement summary descriptions to reference the RT_{PTS} and USE values listed in the report for the limiting PTS and USE materials in the beltline of the reactor vessel.

In its response to Confirmatory Item 4.2.3-1 dated September 16, 2003, the applicant stated that it would amend the FSAR Supplement summary descriptions for the TLAAs on PTS and USE, as given in Sections A.3.2.1 and A.3.2.2, respectively. This proposed amendment has been included in Section 4.2.3 of this SER. The applicant's amended FSAR Supplement summary descriptions for the TLAAs on PTS and USE accomplish the following objectives (1) the amendments provide a sound basis why the TLAAs for PTS and USE, as given in Sections A.3.2.1 and A.3.2.2 of the LRA, comply with the requirements in 10 CFR 50.61 for PTS and in 10 CFR Part 50, Appendix G, for USE through the expiration of the extended period of operation for RNP, and (2) the amendments provide a reference to the extended period of operation licensing basis documents containing the TLAAs for PTS and USE. Since the FSAR Supplement summary descriptions demonstrate while the TLAAs are acceptable and reference the applicable licensing basis documents, the staff therefore concludes that the applicant's

FSAR Supplement summary descriptions for the TLAAs on PTS and USE, as given in Sections A.3.2.1 and A.3.2.2 of the LRA, and amended by the applicant's response to Confirmatory Item 4.2.3-1, are acceptable. Confirmatory Item 4.2.3-1 is resolved.

Confirmatory Item 4.3.2-1 (auxiliary feedwater fatigue analysis)

In RAI 4.3-7, the staff requested the applicant to provide (1) calculated cumulative utilization factors (CUFs) of the six replacement branch connections, (2) confirmation that no other nonstandard components were used or provide justification of the acceptability for use in safety systems at RNP, and (3) description of the AMPs that will be used to provide assurance that the CUFs for these connections will not exceed the limit of 1.0 for the period of extended operation. In its response by a letter dated June 13, 2003, the applicant stated that there are three 4" to 16" auxiliary feedwater-to-feedwater connections downstream of the motor-driven and the steam-driven AFW pump. The three connections downstream from the steam-driven pumps could not be qualified for the full 40-year design transient set, so a reduced number of design transients was postulated. This resulted in a CUF value of 0.99 for 40-year life. Based upon projections of actual transients to date, the qualified number of transients is not expected to be reached until approximately year 50. The applicant indicated that the number of transients used in the analysis will be tracked by the Fatigue Monitoring Program. The applicant further indicated that the components will be either reanalyzed or replaced prior to exceeding the number of transients tracked by the Fatigue Monitoring Program. The staff finds that the applicant's proposed options provide acceptable plant-specific approaches to address fatigue of the connections between the auxiliary and main feedwater lines for the period of extended operation in accordance with 10 CFR 54.21(c)(1). However, in accordance with 10 CFR 54.21(d), these options need to be included in the UFSAR Supplement (Confirmatory Item 4.3.2-1).

By letter dated September 16, 2003, the applicant provided a modification to UFSAR Supplement Section A.3.2.2.1, which includes the proposed options to address fatigue of the connections between the auxiliary and main feedwater lines for the period of extended operation. The staff finds the modification to UFSAR Supplement Section A.3.2.2.1 acceptable. Confirmatory Item 4.3.2-1 is closed.

Confirmatory Item 4.3.2-2 (aging management of surge line for period of extended operation)

In RAI 4.3-10, the staff requested that the applicant provide additional clarification regarding aging management of the surge line during the period of extended operation. The applicant's June 13, 2003, response indicated that fatigue of the surge line will be managed using one or more options. Options include further refinement of the fatigue analyses to maintain the environmentally assisted fatigue (EAF)-adjusted CUF below 1.0, repair of the affected locations, replacement of the affected components, or management of the effects of fatigue through the use of an augmented ISI program reviewed and approved by the NRC.

The applicant commits to provide the NRC with the details of the inspection program prior to the period of extended operation if the last option is selected. As indicated by the applicant, the use of an inspection program to manage fatigue will require prior staff review and approval. The applicant indicated that LRA Section A.3.2.2.2 would be revised to include the applicant's proposed options for managing the surge line fatigue. The staff finds the applicant's proposed options provide acceptable plant-specific approaches to address EAF of the RNP pressurizer surge line for the period of extended operation in accordance with 10 CFR 54.21(c)(1). Revision of the UFSAR Supplement is Confirmatory Item 4.3.2-2.

By letter dated September 16, 2003, the applicant provided a modification to UFSAR Supplement Section A.3.2.2.1, which includes the proposed options to address fatigue of the surge line for the period of extended operation. The staff finds the modification to UFSAR Supplement Section A.3.2.2.1 acceptable. Confirmatory Item 4.3.2-2 is closed.

Confirmatory Item 4.6.3-1 (elimination of containment penetration coolers)

This confirmatory item relates to RAI 4.6.3-2. The staff requested the applicant to describe how the analysis was performed and submit the analysis results of concrete properties at the end of 252 cycles. The staff requested the applicant to clarify whether the conclusion of 252 cycles was obtained from its operating experience. During a teleconference call on June 10, 2003, the applicant stated it had found an analysis result indicating that the temperature in concrete around the containment penetration would always remain below 200 °F. Therefore, the applicant is withdrawing this TLAA item and will submit a new writeup to indicate the withdrawal. Since the applicant's analysis results indicate that the concrete temperature around the containment penetration will always remain below 200 °F with the elimination of containment penetration coolers, the applicant informed the staff in the teleconference that it had withdrawn this TLAA issue and would submit its new writeup accordingly (Confirmatory Item 4.6.3-1). The staff finds the applicant's approach acceptable.

The staff agreed with the applicant's approach of withdrawing this TLAA issue because its analysis results indicate that there is no need for the TLAA. The applicant submitted a letter dated August 14, 2003, to withdraw this TLAA item from the LRA. Therefore, Confirmatory Item 4.6.3-1 is closed.

Confirmatory Item 4.6.4-1 (issued with regard to the staff's assessment of LRA Section B.4.6.4, Aging of Boraflex, as evaluated in Section 4.6.4.2 of the SER)

By letter dated May 28, 2003, the applicant submitted for staff review a license amendment to change the technical specifications regarding removal of Boraflex monitoring procedures. The staff will need confirmation that the license amendment to remove the requirements to credit the Boraflex panels from the RNP technical specification has been approved and that the Boraflex panels will no longer be needed to maintain the effective neutron multiplication factor (K_{eff}) for the geometry of the spent fuel rods stored in the spent fuel pool within acceptable levels. As part of this confirmatory item, the staff will need the applicant to provide a reference regarding the staff's safety evaluation to CP&L approving the license amendment for the Boraflex panels. This confirmatory item also requires the applicant's statement that it will not be necessary to include a summary description of the Boraflex TLAA in the UFSAR Supplement of the application (i.e., in Appendix A of the LRA). This is Confirmatory Item 4.6.4-1.

By letter dated December 22, 2003, License Amendment No. 198, the staff approved the applicant's request to eliminate the need to credit the Boraflex neutron absorbing material for reactivity control in the spent fuel storage pool. In place of the Boraflex material (i.e., panels), the staff approved the applicant's request to take credit for a combination of soluble boron and controlled fuel loading patterns in the spent fuel pool to maintain the required subcriticality margins in the spent fuel storage pool. On the basis of the final issuance of License Amendment No. 198, the staff finds that Confirmatory Item 4.6.4-1 is closed. In addition, the applicant may eliminate its Commitment No. 47 and eliminate any discussion in the RNP UFSAR regarding the Boraflex TLAA or the Boraflex monitoring program.

Confirmatory Item B.3.11-1 (issued with regard to the staff's assessment of LRA Section B.3.11, Reactor Vessel Surveillance Program, as evaluated in Section 3.1.2.3.4 of the SER)

The withdrawal schedule in WCAP-15805 indicates that the in-vessel location for Capsule U was moved sometime within the current life of the plant. Therefore, in a meeting with the applicant on May 21, 2003, the staff requested additional clarifying information regarding the elapsed time when Capsule U was moved in the vessel, what the lead factors were for Capsule U at the different in-vessel locations, and what CP&L's basis was for determining that the projected fluence for Capsule U at its projected time of withdrawal would be indicative of the fluence for the RV shell at 50 effective full-power years (EFPY) (i.e., at the EFPY projected for the end of the extended period of operation for RNP). During the meeting of May 21, 2003, the applicant informed the staff that it would provide the additional information requested by the staff. The applicant submitted the requested information in an E-mail to the staff dated June 9, 2003. The applicant must formally submit the information in the E-mail of June 9, 2003, into the docket for RNP (i.e., into Docket No. 50-261) under "Oath and Affirmation." This is Confirmatory Item B.3.11-1.

In its response to Confirmatory Item B.3.11-1, the applicant submitted the information provided in the email of June 9, 2003, for incorporation into the docket for RNP (i.e, Docket No. 50-261) under oath and affirmation. Since the requested information in the email of June 9, 2003, has been incorporated into the docket for RNP and since the information indicates the RV surveillance capsule withdrawal schedule is acceptable for the period of extended operation for RNP, the staff concludes that the applicant's response to Confirmatory Item B.3.11-1 is acceptable. Confirmatory Item B.3.11-1 is resolved.

Confirmatory Item B.4.1-1 (issued with regard to the staff's assessment of LRA Section B.4.1, Nickel-Alloy Nozzles and Penetrations Program, as evaluated in Section 3.1.2.3.6 of the LRA)

The first paragraph in the UFSAR Supplement summary description for the Nickel-Alloy Nozzles and Penetrations Program is not up to date and needs to be amended to reflect that the applicant's inspection program for the RNP vessel head penetration (VHP) nozzles is based on the requirements in NRC Order No. EA-03-009 (February 11, 2003) and the applicant's response to the order dated March 3, 2003. The applicant must confirm that the UFSAR Supplement summary description for the Nickel-Alloy Nozzles and Penetrations Program (as given in Section A.3.1.28 of Appendix A to the LRA) will be amended to reflect the augmented requirements in NRC Order No. EA-03-009 for the RNP upper reactor vessel head and its VHP nozzles. This is Confirmatory Item B.4.1-1.

The applicant provided its response to Confirmatory Item B.4.1-1 by letter dated September 16, 2003. In this response, the applicant confirmed that the scope of the FSAR Supplement summary description for the Nickel-Alloy Nozzles and Penetrations Program will be amended to include the augmented requirements in NRC Order EA-03-009, as they apply to augmented inspections of the RNP reactor vessel head and VHP nozzles. Since the response confirms that the FSAR Supplement summary description for the AMP will be amended to reflect the applicability of the requirements in NRC Order EA-03-009, the staff concludes that the applicant's response to Confirmatory Item B.4.1-1 is acceptable and Confirmatory Item B.4.1-1 is resolved.

Confirmatory Item B.4.2-1 (issued with regard to the staff's assessment of LRA Section B.4.2, Thermal Aging of Cast Austenitic Stainless Steel Program, as evaluated in Section 3.1.2.3.7 of the SER)

The staff seeks confirmation that, although a leak before break flaw tolerance evaluation has been performed for the extended period of operation for RNP (as given in WCAP-15628), the applicant will continue to perform those ISI examinations for the primary coolant loop piping, valve, and pump casings that are required by Table IWB-2500-1 of Section XI to the ASME Boiler and Pressure Vessel Code, unless relief has been granted by the NRC under applicable provisions in 10 CFR 50.55a from meeting the staff's ISI requirements of 10 CFR 50.55a(g)(4). If relief has been granted from any of the required ISI examinations for the primary coolant loop piping, valve, or pump casings, the staff seeks confirmation of the applicable NRC staff safety evaluation granting this relief and the specific ISI examination requirements for which relief has been granted. The staff also seeks confirmation that the UFSAR Supplement summary description will be amended to reflect the information in the applicant's response to this confirmatory item. This is Confirmatory Item B.4.2-1.

In its response to Confirmatory Item B.4.2-1, dated August 14, 2003, the applicant confirmed that the UFSAR Supplement summary description for the CASS Program will be amended to indicate that the applicant will continue to perform the inservice inspections of the ASME Class 1 primary loop piping, valve bodies, and pump casings, as required by 10 CFR 50.55a and Section XI of the ASME Boiler and Pressure Vessel Code, unless relief has been requested and granted by the NRC under applicable provisions in 10 CFR 50.55a. The applicant also confirmed that the summary description for the CASS program will also be amended to indicate that the NRC did approve some specific relief requests (i.e., in NRC safety evaluation dated September 26, 2002) on some of the specific ISI requirements for the ASME Class 1 primary loop piping, valve bodies, and pump casings for the fourth 10-year ISI interval for RNP.

The staff reviewed the information in the safety evaluation of September 26, 2002, and confirmed that the reliefs granted would not impact the acceptability of the program attributes for the CASS Program. Since the applicant's response to Confirmatory Item B.4.2-1 indicates that the UFSAR Supplement summary description will be modified to demonstrate continued compliance with the requirements of 10 CFR 50.55a and Section XI of the ASME Boiler and Pressure Vessel Code, the staff concludes that the UFSAR Supplement summary description for the CASS Program is acceptable. Confirmatory Item B.4.2-1 is resolved.

Confirmatory Item B.4.3-1 (issued with regard to the staff's assessment of LRA Section B.4.3, PWR Vessel Internals Program, as evaluated in Section 3.1.2.3.8 of the SER)

The staff will confirm that the applicant has incorporated the commitment regarding the Nickel-Alloy Nozzles and Penetrations Program into the UFSAR Supplement summary description of Section A.3.1.30 of Appendix A to the LRA when the applicant revises its UFSAR Supplement for this AMP. This is Confirmatory Item B.4.3-1.

In its response to Confirmatory Item B.4.3-1, the applicant provided the staff with an updated version of Commitment No. 33 in RNP Serial Letter RNP-RA/03-0031, dated April 28, 2003, which included a commitment to submit the inspection plan for the PWR Vessel Internal Program for NRC review and approval. In the response to Confirmatory Item B.4.3-1, the applicant also confirmed that it would amend to UFSAR Supplement summary description for the PWR Vessel Internals Program, as given in Section A.3.1.30 of Appendix A to the LRA, to incorporate a statement that reflects that the PWR Vessel Internal Program will be submitted to the staff for review and approval 24 months prior to implementation. Since the applicant's response reflects the commitment in Commitment No. 33 for submittal of the AMP for staff review and approval, the staff concludes that the applicant's response to Confirmatory Item B.4.3-1 is acceptable and Confirmatory Item B.4.3-1 is resolved.

1.7 Summary of Proposed License Conditions

As a result of the staff's review of the RNP application for license renewal, including the additional information and clarifications submitted subsequently, the staff identified two proposed license conditions. The first license condition requires the applicant to include the UFSAR Supplement in the next UFSAR update required by 10 CFR 50.71(e) following issuance of the renewed license. The second license condition requires that the future inspection activities identified in the UFSAR Supplement be completed prior to the period of extended operation.

2 Scoping and Screening Methodology for Identifying Structures and Components Subject to an Aging Management Review, and Implementation Results

This section documents the U.S. Nuclear Regulatory Commission (NRC) staff's review of the methodology used by the applicant to identify structures, systems, and components (SSCs) that are within the scope of the Rule, and to identify structures and components (SCs) that are within the scope of the Rule and are subject to an aging management review (AMR). SCs subject to an AMR are those that perform an intended function, as described in Title 10 of the *Code of Federal Regulations* (CFR) Part 54 (the Rule), and meet the following two criteria.

(1) They perform such functions without moving parts or without a change in configuration or properties, as set forth in 10 CFR 54.21(a)(1)(i) (denoted as "passive" SCs).

(2) They are not subject to replacement based on a qualified life or specified time period, as set forth in 10 CFR 54.21(a)(1)(ii) (denoted as "long-lived" SCs).

The identification of the SSCs within the scope of license renewal is called "scoping." For those SSCs within the scope of license renewal, the identification of passive, long-lived SCs that are subject to an AMR is called "screening."

The staff's review of the scoping and screening methodology is presented in Section 2.1 of this Safety Evaluation Report (SER). The staff's review of the results of the implementation of the scoping and screening methodology is presented in Sections 2.2 through 2.5 of this SER.

By letter dated June 14, 2002, the applicant submitted its request and application for renewal of the operating license for the H.B. Robinson Steam Electric Plant, Unit No. 2 (RNP). As an aid to the staff during the review, the applicant provided evaluation boundary drawings that identify the functional boundaries for systems and components within the scope of license renewal. These evaluation boundary drawings are not part of the license renewal application (LRA). By letter dated October 23, 2002, the applicant provided supplemental LRA information concerning interim staff guidance for fire protection (FP) system aging management, station blackout (SBO), aging management of concrete components, and 10 CFR 54.4(a)(2).

On February 11, 2003, the staff issued requests for additional information (RAIs) regarding the applicant's methodology for identifying SSCs at RNP that are within the scope of license renewal and subject to an AMR, and the results of the applicant's scoping and screening process. This was supplemented by another RAI dated February 21, 2003. By letter dated April 28, 2003, the applicant provided responses to the RAIs. By letter dated October 23, 2002, the applicant provided supplemental LRA information concerning interim staff guidance for FP system aging management, SBO, aging management of concrete components, and 10 CFR 54.4(a)(2). This was supplemented by a letter dated February 21, 2003 requesting additional information.

The staff conducted a scoping and screening inspection from March 31 to April 4, 2003, to examine activities that supported the LRA, including the inspection of procedures and representative records, and personnel interviews regarding the process of scoping and screening plant equipment to select SSCs within the scope of the Rule and subject to an AMR.

The inspection team found several SSCs which the applicant omitted from the scope of license renewal. When such SSCs were found, the inspection team expanded its inspection to determine whether additional SSCs had been omitted. In each case, no additional SSCs were found to be omitted from scope. With the inclusion within scope of the omitted SSCs, the NRC staff concluded that the applicant's scoping and screening process was successful in identifying those SSCs required to be considered for aging management. In addition, for a sample of plant systems, the inspection team performed visual examinations of accessible portions of the systems to observe any effects of equipment aging. Finally, the inspection concluded that the scoping and screening portion of the applicant's license renewal activities were conducted as described in the LRA and that documentation supporting the application is in an auditable and retrievable form. Inspection open items that were identified during the inspection are discussed in this SER.

2.1 Scoping and Screening Methodology

2.1.1 Introduction

Pursuant to 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," Section 54.21, "Contents of Application—Technical Information," each application for license renewal must contain an integrated plant assessment (IPA). Furthermore, the IPA must identify and list those SCs that are subject to an AMR from the SSCs that are within the scope of license renewal, in accordance with 10 CFR 54.4(a).

In Section 2.1, "Scoping and Screening Methodology," of the LRA, the applicant described the scoping and screening methodology used to identify SSCs at the RNP that are within the scope of license renewal, and SCs that are subject to an AMR. The staff reviewed the applicant's scoping and screening methodology to determine if it meets the scoping requirements stated in 10 CFR 54.4(a) and the screening requirements stated in 10 CFR 54.21.

In developing the scoping and screening methodology for the RNP LRA, the applicant considered the requirements of the Rule, the Statements of Consideration for the Rule, and the guidance presented in the Nuclear Energy Institute's (NEI), "Industry Guideline for Implementing the Requirements of 10 CFR Part 54—The License Renewal Rule," Revision 3, March 2001, (NEI 95-10). In addition, the applicant also considered the NRC staff's correspondence with other applicants and with the NEI in the development of this methodology.

2.1.2 Summary of Technical Information in the Application

In Sections 2.0 and 3.0 of the LRA, the applicant provided the technical information required by 10 CFR 54.21(a). In Section 2.1, "Scoping and Screening Methodology," of the LRA, the applicant described the process used to identify the SSCs that meet the license renewal scoping criteria under 10 CFR 54.4(a), as well as the process used to identify the SCs that are subject to an AMR as required by 10 CFR 54.21(a)(1).

Additionally, Section 2.2, "Plant Level Scoping Results"; Section 2.3, "Scoping and Screening Results—Mechanical Systems"; Section 2.4, "Scoping and Screening Results—Structures"; and Section 2.5, "Scoping and Screening Results—Electrical and Instrumentation and Control (I&C) Systems," of the LRA amplify the process that the applicant used to identify the SCs that are subject to an AMR. Chapter 3 of the LRA, "Aging Management Review Results," contains the following information:

- Section 3.1, "Aging Management of Reactor Vessel, Internals, and Reactor Coolant System"
- Section 3.2, "Aging Management of Engineered Safety Features"
- Section 3.3, "Aging Management of Auxiliary Systems"
- Section 3.4, "Aging Management of Steam and Power Conversion Systems"
- Section 3.5, "Aging Management of Containments, Structures, and Component Supports"
- Section 3.6, "Aging Management of Electrical and Instrumentation and Controls"
- Chapter 4 of the LRA, "Time-Limited Aging Analyses," contains the applicant's identification and evaluation of time-limited aging analyses

2.1.2.1 Scoping Methodology

2.1.2.1.1 Application of the Scoping Criteria in 10 CFR 54.4(a)

10 CFR 54.4(a)(1)

In Sections 2.1, "Scoping and Screening Methodology"; 2.1.1, "Scoping"; and 2.1.1.1, "Safety-Related Criteria Pursuant to 10 CFR 54.4(a)(1)," of the LRA, the applicant discussed the scoping methodology as it related to the safety-related criteria found in 10 CFR 54.4(a)(1).

The LRA states that 10 CFR 54.4(a)(1) pertains to safety-related SSCs and that SSCs within the scope of license renewal include safety-related SSCs which are relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49 (b)(1)) to ensure the following functions:

- *the integrity of the reactor coolant pressure boundary*
- the capability to shut down the reactor and maintain it in a safe shutdown condition
- the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11, as applicable

In addition, the LRA states that these criteria are consistent with those used to develop the original Q-List at RNP, as documented in the RNP Continuing Quality Assurance Program Manual and the RNP procedures that control the Q-List. Consistent with commitments in the RNP current licensing basis (CLB), the RNP Q-List criteria define the SSCs relied upon to remain functional during and following design-basis events described in Chapter 15 of the Updated Final Safety Analysis Report (UFSAR), as well as in other sections of the UFSAR where the design bases for SSCs are defined by postulated events such as earthquakes and other external hazards.

The process of identifying safety-related SSCs included the use of the RNP PassPort Equipment Database (EDB) as the primary source used to define a comprehensive list of the systems and structures that make up the RNP, and to identify those systems and structures that are classified as safety related. The EDB was developed using the RNP Q-List and extends the classification of systems to the component level. For the purposes of license renewal, any system/structure, including support systems, that contains one or more safety-related components was considered to be a safety-related system/structure.

The RNP design and CLB documentation were also reviewed to compile a comprehensive list of functions that each system and structure at RNP is credited with performing. Primary sources of this information include design-basis documents (DBDs), the EDB, and the UFSAR. System functions that meet the criteria of 10 CFR 54.4(a)(1) were identified. These are the system/structure intended functions that are the basis for inclusion in license renewal scope.

<u>10 CFR 54.4(a)(2)</u>

In Sections 2.1, "Scoping and Screening Methodology"; 2.1.1, "Scoping"; and Section 2.1.1.2, "Non-Safety-Related Criteria Pursuant to 10 CFR 54.4(a)(2)," of the LRA, the applicant discussed the scoping methodology as it related to the non-safety-related criteria found in accordance with 10 CFR 54.4(a)(2). With respect to the non-safety-related criteria, the applicant stated, in part, that a review has been performed to identify those non-safety-related SSCs whose failure could prevent satisfactory accomplishment of the safety-related intended functions identified in 10 CFR 54.4(a)(1).

The LRA states that 10 CFR 54.4(a)(2) indicates that SSCs within the scope of license renewal include those non-safety-related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified for safety-related SSCs. The relationship by which this criterion of 10 CFR 54.4(a)(2) might be satisfied takes on one of two forms (1) functional dependencies, wherein non-safety-related equipment is required to perform a function in order to support the function of safety-related equipment, or (2) physical interactions, wherein the failure of non-safety-related equipment might inhibit the performance of nearby safety-related equipment (e.g., seismic interaction, flooding effects, high-energy line break effects, etc.). At RNP, the procedural requirements for component classification state that components that do not perform a safety-related function, but whose failure could prevent the satisfactory accomplishment of a safety-related function during or following design-basis accidents and transients, are to be classified as safety-related. However, there are instances in which the CLB permits use of non-safety-related systems to support the function of safety-related systems. In these cases, the systems are classified in accordance with CLB commitments. Therefore, an evaluation was performed to assure that all SSCs meeting the criteria of 10 CFR 54.4(a)(2) were identified.

In addition, the LRA states that the RNP design and licensing basis information was reviewed to identify non-safety-related SSCs that directly support a safety-related system or structure and whose failure could prevent the performance of a required intended function. Sources of this information included design basis documents, the UFSAR, the EDB, the Maintenance Rule Database, and docketed correspondence. Each instance was identified in which non-safety-related SSCs were credited in the performance of an intended function or whose failure could prevent the performance of an intended function of a safety-related SSC. In each case, the specific function that is required of the non-safety-related system/structure was identified. The SSCs meeting these criteria were designated as within the scope of license renewal in accordance with the 10 CFR 54.4(a)(2) criteria, and the associated function or interaction was considered to be a system/structure intended function.

The RNP design and licensing basis information was reviewed to identify non-safety-related SSC interactions with safety-related SSCs that could prevent the performance of a required intended function. Sources of this information included design-basis documents, the UFSAR, plant drawings, and other CLB documentation, as well as the EDB and the Maintenance Rule Database. For each such instance, the specific interaction that might affect the function of safety-related SSCs was identified. The SSCs meeting these criteria were designated as within the scope of license renewal in accordance with the 10 CFR 54.4(a)(2) criteria, and the associated interaction was considered to be a system/structure intended function.

The LRA also states that interactions of nonseismically qualified SSCs with seismically qualified SSCs (commonly referred to as Seismic II over I) are not part of the CLB for RNP. The RNP CLB, however, considers the effects of physical interactions on the SSCs necessary to achieve and maintain safe shutdown, consistent with the plant's responses pertaining to resolution of Unresolved Safety Issue (USI) A-46. The USI A-46 review imposed criteria for evaluating interactions between seismically qualified SSCs and nonseismically qualified SSCs associated with proximity, structural failure and falling, and flexibility of attached cables and piping. This type of interaction was considered in the license renewal process, and a spaces- or area-based approach was used to identify components in this category. As part of the screening process, a plant area-based approach was implemented to identify spatial interactions between non-safety-related SSCs and safety-related SSCs that could adversely affect the accomplishment of an intended function. Plant walkdowns were performed to identify potential seismic interactions and non-safety-related structural components (e.g., pipe supports, raceway supports, equipment supports, and miscellaneous structures) associated with seismic interactions were identified based on their location relative to safety-related SSCs.

10 CFR 54.4(a)(3)

In Sections 2.1, "Scoping and Screening Methodology"; 2.1.1, "Scoping"; and Section 2.1.1.3, "Other Scoping Pursuant to 10 CFR 54.4(a)(3)," of the LRA, the applicant discussed the scoping methodology as it related to the regulated event criteria found in 10 CFR 54.4(a)(3).

The LRA states that 10 CFR 54.4(a)(3) indicates that SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for FP (10 CFR 50.48), environmental qualification (EQ) (10 CFR 50.49), pressurized thermal shock (PTS) (10 CFR 50.61), anticipated transients without scram (ATWS) (10 CFR 50.62), and station blackout (SBO) (10 CFR 50.63) are within the scope of license renewal. CLB evaluations have been performed and documented which facilitate the identification of those SSCs credited in compliance with each of these regulations. For these SSCs, the system/structure level intended function is that function which is relied upon in safety analyses or evaluations to demonstrate compliance with NRC requirements for the regulated event. A system/structure function-based approach is not needed to identify intended functions, but can be used as necessary to identify the boundaries of credited equipment. Systems or structures that have one or more components credited for demonstrating compliance with one of the regulated events are within the scope of license renewal in accordance with the 10 CFR 54.4(a)(3) criteria.

2.1.2.1.2 Documentation Sources Used for Scoping and Screening

In Sections 2.1.1.1, 2.1.1.2, 2.1.1.3, 2.1.2.1, 2.1.2.2, and 2.1.2.3 of the LRA, the applicant stated that information derived from the CLB, licensing-basis documents, DBDs, the UFSAR, plant drawings, the Q-List, the Maintenance Rule Database, and the EDB was reviewed during the license renewal scoping and screening process. The applicant used this information to identify the functions performed by plant systems and structures. These functions were then compared to the scoping criteria in 10 CFR 54(a)(1-3) to determine if the associated plant system or structure performed a license renewal intended function. These sources were also used to develop the list of SCs subject to an AMR.

2.1.2.2 Screening Methodology

2.1.2.2.1 Mechanical Screening

The LRA states that following the scoping for mechanical systems, the applicant performed screening to identify those mechanical components that were subject to an AMR. The applicant stated in Section 2.1.2.1, "Mechanical Systems," of the LRA that the following methodology was used.

For mechanical systems, the screening process was performed on each system identified to be within the scope of license renewal. This process evaluated the individual components included within in-scope mechanical systems to identify specific components or component groups that require an AMR.

For the systems in scope for license renewal, mechanical system evaluation boundaries were established. Generally, these boundaries were determined by mapping the pressure boundary associated with license renewal system intended functions onto the system flow diagrams. License renewal system intended functions are the functions a system must perform relative to the scoping criteria of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3).

The evaluation boundaries associated with license renewal system intended functions were mapped onto the system's flow diagram. The entire flow path was considered to include all components credited for the successful completion of each intended function.

Based on a review of flow diagrams, design drawings, plant documentation, and the system component list from the EDB, components that were included within the system intended function boundaries were identified. Although mechanical system intended function boundaries ordinarily occur at a valve location, the seismic boundary may extend to a support past the valve and may include a section of non-safety-related piping. This piping segment and the associated support also were included in the scope of license renewal.

The components within the system intended function boundary that perform an intended function without moving parts or without a change in configuration or properties (i.e., the screening criteria of 10 CFR 54.21(a)(1)(i)), were identified. Active and passive screening determinations were based on the guidance in Appendix B to NEI 95-10. Part 54.21(a)(1)(i) of Title 10 of the *Code of Federal Regulations* provides a summary of specific component types that are excluded from the scope of license renewal. These specific component types are screened based on the provisions of the Rule. Some components were determined to be part of a complex assembly as discussed in NEI 95-10 and were screened accordingly.

The passive, in-scope components that were not subject to replacement based on a qualified life or specified time period (the screening criteria of 10 CFR 54.21(a)(1)(ii)) were identified as requiring an AMR. The determination of whether passive, in-scope components have a qualified life or specified replacement time period was based on a review of plant-specific information including the EDB, maintenance programs, and procedures.

The components that were within the scope of license renewal (i.e., required to perform a license renewal system intended function) were identified and the component intended functions for in-scope components were identified. The component intended functions identified were based on the guidance of NEI 95-10.

2.1.2.2.2 Structural Screening

The LRA states that following structural scoping, the applicant performed screening to identify those civil/structural components that were subject to an AMR. In Section 2.1.2.2, "Civil Structures," of the LRA, the applicant described the methodology used to screen civil/structural components. The applicant stated that the following civil/structural screening methodology was used.

The applicant performed the screening process on each structure identified to be within the scope of license renewal. This method evaluated the individual SCs included within in-scope structures to identify specific SCs or SC groups that require an AMR.

The evaluation boundaries associated with each civil/structural intended function were identified and documented using appropriate drawings and other documentation. Evaluation boundaries between mechanical components, electrical components, and structures and structural components were coordinated between the discipline reviewers. The civil/structural components included items such as walls, supports, and non-current carrying electrical and I&C components (i.e., conduits, cables trays, electrical enclosures, panels, and related supports). Civil/structural intended functions were identified during performance of the scoping process.

Based on a review of the civil/structural evaluation boundaries, the SCs and commodity types within the intended function boundaries for the given structure were identified and documented. A generic list of commodity types was developed using guidance from Table 4.1-1 of NEI 95-10, and potential intended functions for the commodity types were identified. Structural components were identified using the EDB as a starting point. In the screening process, no differentiation was made between individual component and commodity types; they were grouped together under common types. Implementation of this methodology conservatively includes many components and commodities within the scope of license renewal that otherwise would be screened out as not supporting any system intended function.

The in-scope SCs that performed an intended function without moving parts or without a change in configuration or properties (the screening criterion of 10 CFR 54.21(a)(1)(i)), or that are not subject to replacement based on a qualified life or specified time period (the screening criteria of 10 CFR 54.21(a)(1)(ii)), were identified. Active/passive screening determinations were based on the guidance in Appendix B to NEI 95-10.

Component intended functions for in-scope SCs were determined and documented. The component intended functions were based on the guidance of NEI 95-10. Those SCs that have a component or commodity group intended function that supports a structure intended function were determined to be subject to an AMR.

2.1.2.2.3 Electrical and Instrumentation and Controls (I&C) Screening

The LRA states that screening of electrical and I&C system components was performed differently than for mechanical and structural components. In Section 2.1.2.3, "Electrical and I&C Systems," of the LRA, the applicant described the methodology used to screen electrical and I&C components.

The LRA stated that the method used to determine which electrical and I&C components were subject to an AMR was based on the component commodity group approach consistent with the guidance of NEI 95-10. The primary difference between this method and the method used for mechanical systems and structures was the order in which the component screening steps were performed. This method was selected for use with the electrical and I&C components because most electrical and I&C components are active.

Using the EDB, appropriate plant design drawings, and other documentation, the different types of electrical components within the electrical and I&C systems determined to be in scope for license renewal were identified. The component types associated with the electrical and I&C systems within the scope of license renewal were organized into commodity groupings (i.e., circuit breakers, cables, sensors). In general, grouping of component types followed the guidance in NEI 95-10 regarding grouping of components based on similar functions.

The electrical and I&C component commodity groups that perform an intended function without moving parts, or without a change in configuration or properties (the screening criteria of 10 CFR 54.21(a)(1)(i)), were identified. Active or passive screening determinations were based on the guidance in Appendix B to NEI 95-10. Commodity groups that have passive functions and may be subject to an AMR were identified.

For the passive electrical and I&C component commodity groups, component commodity groups that are not subject to replacement based on a qualified life or specified time period (the screening criteria of 10 CFR 54.21(a)(1)(ii)) were identified as requiring an AMR. Commodity group components that are replaced based on qualified life, determined in accordance with the Environmental Qualification Program, were determined not to be subject to AMR.

2.1.3 Staff Evaluation

As part of the review of the applicant's LRA, the NRC staff evaluated the scoping and screening activities described in the following sections of the application to assure that the applicant outlined a process for determining structural, mechanical, and electrical components at RNP that are subject to an AMR for renewal, in accordance with the requirements of 10 CFR 54.21(a)(1) and 10 CFR 54.21(a)(2):

- Section 2.1, "Scoping," to ensure that the applicant described a process for identifying SSCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3)

- Section 2.2, "Plant Level Scoping Results"; Section 2.3, "Scoping and Screening Results—Mechanical Systems"; Section 2.4, "Scoping and Screening Results—Structures"; and Section 2.5, "Screening Results—Electrical and Instrumentation and Control (I&C) Systems"

In addition, the staff conducted a scoping and screening methodology audit at RNP from September 17 through 20, 2002. The focus of the audit was to ensure that the applicant had developed and implemented adequate guidance to conduct the scoping and screening of SSCs in accordance with the methodologies described in the application and the requirements of the Rule. The audit team reviewed implementation procedures and calculations which describe the scoping and screening methodology implemented by the applicant. The applicant documented the results of licensee renewal evaluations by means of calculations. In addition, the audit team conducted detailed discussions with the cognizant engineers on the implementation and control of the program, and reviewed administrative control documentation and selected design documentation used by the applicant during the scoping and screening process. The audit team further reviewed a sample of system scoping and screening results reports for safety injection, auxiliary feedwater, component cooling water, and main feedwater to ensure that the methodology outlined in the administrative controls was appropriately implemented. The results were found to be consistent with the CLB, as described in the supporting design documentation.

2.1.3.1 *Scoping Methodology*

The audit team reviewed implementation procedures and calculations which described the scoping and screening methodology implemented by the applicant. These procedures included EGR-NGGC-0501, "Nuclear Plant License Renewal Plan," Revision 3; EGR-NGGC-0502, "System Structure Scoping for License Renewal," Revision 3; and RNP-L/LR-0007, "System Structure Scoping for License Renewal," Revision 3. The team found that the scoping and screening methodology instructions were consistent with Section 2.1 of the LRA and were of sufficient detail to provide the applicant's staff with concise guidance on the scoping and screening implementation process to be followed during the LRA activities. In addition to the implementing procedures, the audit team reviewed portions of the UFSAR, DBDs, the EDB, system drawings, and selected licensing documentation which were relied upon by the applicant during the scoping and screening phases of the review.

2.1.3.1.1 Application of the Scoping Criteria in 10 CFR 54.4(a)

<u>10 CFR 54.4(a)(1)</u>

Pursuant to 10 CFR 54(a)(1), the applicant must consider all safety-related SSCs which are relied upon to remain functional during and following design-basis events to ensure the following functions, (i) the integrity of the reactor coolant pressure boundary, (ii) the capability to shut down the reactor and maintain it in a safe shutdown condition, or (iii) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or

10 CFR 100.11, are included within the scope of license renewal. The audit team determined that the applicant had included the criteria for safety-related SSCs, as defined in 10 CFR 54(a)(1), in both the LRA and the license renewal implementing procedures.

The applicant used the EDB, which contained the list of safety-related components, as the primary source to determine the systems which would be in scope in accordance with the requirements of 10 CFR 54.4(a)(1). Additional sources included the UFSAR, DBDs, and the CLB. The EDB was developed using the RNP Q-List and extends the classification of systems to the component level. The applicant had determined that any system which contained a safety-related component, as indicated by the EDB would be considered in scope in accordance with 10 CFR 54.4(a)(1). The applicant had documented system scoping on scoping worksheets developed for each system listed in the EDB.

The audit team determined that the system and component intended functions had been identified in the system DBDs. However, during the scoping process, certain intended functions had been grouped and reworded (relative to the intended functions contained in the DBDs) when listed on the scoping worksheets. This issue was identified as RAI 2.1.1-3 in the NRC letter to the applicant dated February 11, 2003.

By letter to the NRC dated April 28, 2003, in response to RAI 2.1.1-3, the applicant indicated that the process of identifying system intended functions included (1) determining design-basis information, (2) cataloging potential, system level, intended functions and maintaining the associated source references, (3) determining relevant DBD functional statements, and (4) comparing the functional statements with information cataloged from other CLB sources.

The applicant identified duplicate or overlapping functional statements and used the one that best described the broadest aspects of the function. If necessary, the statements were expanded to capture the complete functional requirements within the basis for modifications or statements provided. This was in the form of a reference or comment that described the relevant information. The applicant made a determination on whether the functional statement was an intended function and recorded the basis in the form of a reference or a comment. The final set of functions was listed on the appropriate system worksheet.

The applicant stated that the scoping process and results had subsequently been the subject of a self-assessment, as well as a Nuclear Assessment Section assessment. The applicant further stated that there were no cases identified of incomplete, missing, or incorrect intended functions. Based on the information reviewed during the audit and the supplemental information provided by the licensee, the audit team concluded that the applicant had applied an acceptable method for determining and documenting intended functions. Therefore, RAI 2.1.1-3 is considered resolved.

As part of the review of the applicant's scoping methodology, the audit team reviewed a sample of the license renewal database, 10 CFR 54(a)(1) scoping results, and the analyses and documentation to support these reviews, and discussed the methodology and results with the applicant's personnel responsible for these evaluations. The team verified that the applicant had identified and used pertinent engineering and licensing information in order to determine the SSCs required to be in scope, in accordance with the 10 CFR 54.4(a)(1) criteria. On the basis of this sample review and discussions with the applicant, the audit team determined that the applicant's methodology for identifying systems and structures meeting the scoping criteria of 10 CFR 54(a)(1) was adequate.

<u>10 CFR 54.4(a)(2)</u>

10 CFR 54(a)(2) requires, in part, that the applicant consider all non-safety-related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs 10 CFR 54(a)(1)(i), 10 CFR 54(a)(1)(ii), or 10 CFR 54(a)(1)(iii) to be within the scope of license renewal.

As part of the evaluation of the applicant's scoping methodology associated with the 10 CFR 54.4(a)(2) criteria, the applicant presented the audit team with a detailed discussion on the development and current implementation of the pertinent design calculations. The audit team also provided the applicant with additional information on the treatment of non-safety-related SSCs affecting safety-related SSCs described in the staff's Interim Staff Guidance (ISG) documents, and reviewed the design calculations developed by the applicant to address the evaluation of the plant SSCs for this topic. Specifically, the staff noted that, by letters dated December 3, 2001, and March 15, 2002, respectively, the NRC issued a staff position to the NEI which described areas to be considered and options it expects licensees to use to determine the SSCs that meet the 10 CFR 54.4(a)2 criteria (i.e., all non-safety-related SSCs whose failure could prevent satisfactory accomplishment of any safety-related functions identified in paragraphs (a)(1)(i), (ii), and (iii) of 10 CFR 54.4).

The letter of December 3, 2001, provided specific examples of operating experience which identified pipe failure events (summarized in Information Notice (IN) 2001-09, "Main Feedwater *System Degradation in Safety-Related ASME Code Class 2 Piping Inside the Containment of a* Pressurized Water Reactor") and the approaches the NRC considers acceptable to determine which piping systems should be included in scope based on the 10 CFR 54.4(a)2 criteria.

The March 15, 2002, letter further described the staff's expectations for the evaluation of nonpiping SSCs to determine which additional non-safety-related SSCs are within scope. The letter states that applicants should not consider hypothetical failures, but rather should base their evaluation on the plant's CLB, engineering judgment and analyses, and relevant operating experience. The letter further describes operating experience as all documented plant-specific and industry-wide experience that can be used to determine the plausibility of a failure. Documentation could include NRC generic communications and event reports, plant-specific condition reports, industry reports such as safety evaluation reports, and engineering evaluations.

Consistent with the staff position described in the aforementioned letters, the staff reviewed the draft calculations prepared by the applicant to resolve the 10 CFR 54.4(a)(2) ISG issues. These calculations were developed by the applicant's engineering staff to help ensure that all SSCs in the CLB that address the requirements of 10 CFR 54.4(a)(2) have been identified and considered for inclusion in the scope of the LRA. The calculation RNP-L/LR-0006, "Non-Safety-Related Equipment Affecting Safety-Related Equipment—License Renewal System/Structure Scoping," specifically provides detailed guidance for evaluating potential non-safety-related SSCs affecting safety-related SSCs, including interpretation of guidelines to be considered during the application of the 10 CFR 54.4(a)(2) requirements, description of interactions and events including functional dependencies between non-safety-related and safety-related SSCs, and physical dependencies between these systems. The calculation also includes a description of mitigative and support functions and a summary of potential interactions of interest as a result of certain operational occurrences, such as flooding, high winds, heavy loads, and high-energy line breaks. The applicant developed two additional calculations, RNP-L/LR-0396, "Screening and Aging Management Review Criterion 2 Piping," and RNP-L/LR-0393, "Aging Management Review Seismic Piping (II over I and Seismic Continuity Piping)," to further describe the scoping and screening criteria established for the review, identify affected systems considered within scope, and identify information associated with the AMR (i.e., material environment combinations for each). The RNP-L/LR-0396 calculation also contained a walkdown worksheet for each system evaluated which described the structure housing the system of interest and the reviewers' comments during the walkdown. The audit team reviewed these calculations and verified that the applicant had adequate plans to incorporate the results of these efforts into the scoping methodology process. However, the audit team identified certain discrepancies between the scoping and screening process described in the current calculations and the actual process that was described by the applicant's staff during the audit activities. Specifically, the calculation RNP-L/LR-0006 did not provide a clear description and account of all essential activities in the scoping and screening process related to the determination of Criterion 2 SSCs. The report described a process by which only certain non-safety-related SSCs would be brought into scope if failure of these non-safety-related SSCs is postulated in the CLB and their failure would result in the loss of a safety-related intended function. In fact, during the methodology audit, the audit team clearly established that the Rule required that all non-safety-related SSCs whose failure could result in the loss of ability of a safety-related SSC to perform its intended function would be included in scope. As a result of reviewing prior LRA application correspondence, the applicant had revised its design documentation to strike the criterion which specified that only certain safety-related equipment must be included. The applicant showed the audit team a draft of the revised calculation which did contain the revision. The team found that the revision adequately addressed the staff's concerns.

As a result of the discussions on the 10 CFR 54.4(a)(2) evaluation and a review of the draft calculations prepared by the applicant, the audit team indicated that an RAI would be forthcoming on the issue to allow the applicant an opportunity to complete implementation of the revisions to the draft calculations, perform the evaluations as described in those calculations, and provide the staff with the results from that effort. This issue was identified as RAI 2.1.1-1 in the NRC letter to the applicant dated February 11, 2003.

By letter to the NRC dated October 23, 2003, the applicant provided the information contained in the draft calculations, discussed above, which had been previously reviewed during the audit and determined to be acceptable. The information contained a list of piping systems included within the modified license renewal scope which had been determined to be in scope in accordance with 10 CFR 54.4(a)(2), identification of the piping systems having non-safety-related components requiring an AMR, and the aging management programs (AMPs) credited for managing the identified aging effects. The staff's review of the applicant's scoping results and aging management evaluation of SCs in these systems is presented in Section 2 and 3 of this SER, respectively. The applicant indicated that site-specific and industry operating experience was reviewed in support of AMRs. Operating experience sources considered included Institute of Nuclear Power Operations operating experience items, NRC documents (information notices, generic letters, violations, and staff reports), 10 CFR Part 21 reports, and vendor bulletins, as well as corporate internal operating experience information from Progress

Energy nuclear sites. In addition, this information was included in the letter to the NRC, dated April 28, 2002, which was provided in response to RAI 2.1.1-1.

The staff reviewed the additional information supplied by the applicant, including (1) expansion of the systems within the scope of license renewal and addition of new portions of systems within scope as a result of the revised methodology, (2) determination of the credible failures which could impact the ability of safety-related SSCs to perform their intended functions, (3) evaluation of relevant operating experience, and (4) incorporation of identified non-safety-related SSCs into the applicant's AMPs and the results of NRC inspection and audit activities. On the basis of the review of the above information and documents, the staff concludes that the applicant has supplied sufficient information to demonstrate that all SSCs that meet the 10 CFR 54.4(a)(2) scoping requirements have been identified as within the scope of license renewal. Therefore, RAI 2.1.1-1 is considered resolved.

<u>10 CFR 54.4(a)(3)</u>

10 CFR 54.4(a)(3) requires, in part, that the applicant consider all SSC's relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63) to be within the scope of the license renewal.

The applicant used CLB evaluations which had been performed and documented to facilitate the identification of those SSCs credited in compliance of 10 CFR 54.4(a)(3). For these SSCs, the system/structure level intended function is that which is relied upon in safety analyses or evaluations to demonstrate compliance with NRC requirements for the event in question. Systems or structures that have one or more components credited for demonstrating compliance with one of the regulated events are within the scope of license renewal in accordance with the 10 CFR 54.4(a)(3) criteria. The applicant had identified the SSCs credited in the CLB by reviewing the CLB and applicable documentation. Also, by letter to the NRC dated October 23, 2003, the applicant responded to the ISG-02 regarding scoping of equipment relied on to meet the requirements of the Station Blackout Rule (10 CFR 50.63) for License Renewal (10 CFR 54.4(a)(3)).

As part of the review of the applicant's scoping methodology, the audit team reviewed a sample of the license renewal database 10 CFR 54(a)(3) scoping results, and a sample of the analyses and documentation to support these reviews, and discussed the methodology and results with the applicant's personnel responsible for these evaluations. The team verified that the applicant had identified and used pertinent engineering and licensing information to determine the SSCs required to be in scope in accordance with the 10 CFR 54.4(a)(3) criteria. Based on this sampling review and discussions with the applicant, the audit team determined that the applicant's methodology for identifying systems and structures meeting the scoping criteria of 10 CFR 54(a)(3) was adequate.

2.1.3.1.2 Mechanical Scoping

The applicant performed a review of all systems and structures in accordance with calculation RNP-L/LR-0007, "System/Structure Scoping for License Renewal," and standard procedure

EGR-NGGC-0502, "System/Structure Scoping for License Renewal." The calculation and procedure provided guidance for the identification of systems and structures included within the scope of license renewal. The documents described sources of information required to determine if any SSCs satisfied the 10 CFR 54.4(a)(1-3) criteria and additional rules for identifying mechanical intended functions. The calculation also provided a worksheet for each mechanical system/structure identified during the scoping activities and indicated whether that mechanical system/structure was considered in scope, which of the 10 CFR 54.4 criteria it satisfied, and the specific intended functions for that structure.

The applicant initially identified all systems listed in the EDB which contain safety-related mechanical components for inclusion within scope of renewal. For each system which satisfied the criteria established in RNP-L/LR-0007, the applicant developed a detailed worksheet. The system intended functions were determined from a review of detailed design documentation such as the UFSAR, DBDs, generic issues documents, evaluation reports for the regulated events, and vendor specifications where necessary.

The audit team reviewed a sample of system scoping and screening results reports for safety injection, auxiliary feedwater, component cooling water, and main feedwater to ensure that the methodology outlined in the administrative controls was appropriately implemented. The results reports were found to be consistent with the CLB as described in the supporting design documentation. The audit team discussed the process and results with the cognizant engineers who performed the review. The audit team did not identify any discrepancies between the methodology documented and the implementation results.

2.1.3.1.3 Structural Scoping

The applicant performed a review of all systems and structures in accordance with calculation RNP-L/LR-0007 and standard procedure EGR-NGGC-0502. The calculation and procedure provided guidance for the identification of systems and structures included within the scope of license renewal. With respect to structure scoping, the documents described sources of information required to determine if any structures satisfied the 10 CFR 54.4(a)(1-3) criteria and additional rules for identifying structure intended functions. The calculation also provided a worksheet for each structure identified during the scoping activities and indicated whether that structure was considered in scope, which of the 10 CFR 54.4 criteria it satisfied, and the specific intended functions for that structure. The audit team reviewed a sample of the structure worksheets developed in accordance with the calculation and did not identify any discrepancies between the sample reviewed and the guidance requirements.

The applicant first identified all structures with unique mark numbers from the EDB for inclusion within scope of renewal. Those structures within the database were typically safety-related structures. The applicant reviewed a series of detailed drawings of plant structures to identify initially all structures at the facility. These structures were then further evaluated through walkdowns of the physical structure to determine which structures housed safety-related equipment or could pose an interaction with, and potentially affect, safety-related equipment, and to determine which structural components needed to be addressed. Those structures that could potentially prevent satisfactory failure of a safety-related function were classified as safety-related by the applicant and addressed as such in the EDB. For each structure which satisfied the criteria established in RNP-L/LR-0007, the applicant developed a detailed worksheet. The structure intended functions were derived from component level data in the

EDB, if available, and from review of detailed design documentation, such as the UFSAR, DBDs, generic issues documents, evaluation reports for the regulated events, and vendor specifications where necessary.

As a secondary evaluation method, the applicant then performed a review of all mechanical and electrical system components that were determined to be within the scope of license renewal and identified which structures contained any of these components. The results were compared to the initial list of structures identified in the EDB and additional structures were added to scope if they satisfied one of the scoping criteria.

The audit team reviewed a sample of the structural drawing packages assembled by the applicant for the reactor containment building and intake structure and discussed the process and results with the cognizant engineers who performed the review. The audit team did not identify any discrepancies between the methodology documented and the implementation results.

2.1.3.1.4 Electrical and Instrumentation and Controls Scoping

The applicant performed electrical and I&C component scoping and screening using the commodity group method. Electrical and I&C scoping and screening is discussed in Section 2.1.3.2.3.

2.1.3.2 Screening Methodology

2.1.3.2.1 Mechanical Screening

The audit team reviewed the screening implementation procedures and a selected sample of the system screening reports to ensure consistent application of the applicant's screening methodology. The applicant developed standard procedure EGR-NGGC-0503, "Mechanical Component Screening for License Renewal," to define the process for performing screening of mechanical components.

The applicant established mechanical system evaluation boundaries for SSCs which had been determined to be within scope. Generally, these boundaries were determined by mapping the pressure boundary associated with the license renewal system intended functions onto the system flow diagrams. The entire flow path was considered to include all components credited for the successful completion of each intended function. The applicant identified the components that were included in the system through a review of flow diagrams, design drawings, plant documentation, and the system component list from the EDB.

The applicant then determined the components within the system intended function boundary that performed an intended function without moving parts or without a change in configuration or properties. Active/passive screening determinations were based on the guidance in Appendix B to NEI 95-10. The passive, in-scope components that were not subject to replacement based on a qualified life or specified time period were identified as requiring an AMR. The determination of whether a passive, in-scope component has a qualified life or specified replacement time period was based on a review of plant-specific information including the EDB, maintenance programs, and procedures. The passive, in-scope components that are not subject to replacement based on a qualified life or specified time period (i.e., screening criteria of 10 CFR 54.21(a)(1)(ii)) were identified as requiring an AMR. The in-scope components identified as requiring an AMR were then compared to the NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," dated July 2001, to ensure that differences are valid and justified. The components that were determined to be within the scope of license renewal were identified and the component intended functions for in-scope components were identified. The component intended functions identified were based on the guidance of NEI 95-10.

The results of the mechanical component screening process were documented in system screening reports which contained the system intended function boundaries, identified the components subject to screening, and documented the screening results for each system component. The component documentation included the component ID, commodity type, screening results (active or passive), the supporting reference calculation, a description, and the intended function. The audit team reviewed a sample of the mechanical screening packages assembled by the applicant and discussed the process and results with the cognizant engineers who performed the review. The audit team did not identify any discrepancies between the screening methodology documented and the implementation results.

2.1.3.2.2 Structural Screening

The audit team reviewed the screening implementation procedures and a selected sample of the structure screening reports to ensure consistent application of the applicant's screening methodology. The applicant developed calculation RNP-L/LR-0124, "License Renewal—Identification of Civil Commodity Types and Bulk Screening Criteria," and standard procedure EGR-NGGC-0506, "Civil/Structural Screening and Aging Management Review for License Renewal," to define the process for performing screening and AMRs of the civil/structural components and to identify typical civil commodity types pertinent to the RNP design. The procedure also provided a description of the criteria to establish evaluation boundaries for each structure. In order to determine which commodity types were applicable to RNP, the applicant compared the commodity listings developed in the NEI 95-10 guidance, as well as all those identified by previous license renewal applicants. The resultant list of commodities captured those items relevant to the RNP design. In addition, the calculation provided a list of 13 component intended functions which were used during the screening process to establish which specific components or commodity types supported a structure intended function.

Because most structural members (e.g., walls, beams, grating, foundations, duct banks, sumps, etc.) do not have individual mark numbers, the structural screening was initiated by first identifying structural members which support the intended function(s) that the structure performs. The structural members were identified by reviewing detailed structural drawings for the in-scope structures. After the structural members were identified, they were assigned to commodity groups where applicable and identified as such in the structural screening calculations. When structures and structural members did not have unique identifier numbers, the applicant's methodology called for creating a pseudo system number for the purposes of cataloging the structure or structural component within the framework of the screening process.

The applicant developed calculations RNP-L/LR-0103, "License Renewal Screening—Structures and Structural Components," and RNP-L/LR-0104, "License Renewal Screening—Containment Structure, Internal and External Structural Components," to capture the results of the screening effort. The calculations provided a concise list of structures and structural components subject to an AMR and described and justified the methodology used to develop that list. The in-scope components identified as requiring an AMR were then compared to the Generic Aging Lessons Learned (GALL) Report to ensure that differences are valid and justified. Additionally, the calculations provided a description of each structure, identified the structure intended functions and the structure evaluation boundary, and described all components which were transferred into the system from other disciplines (e.g., mechanical, electrical) or other structural systems. The audit team reviewed a sample of the structural screening packages assembled by the applicant and discussed the process and results with the cognizant engineers who performed the review. The audit team did not identify any discrepancies between the screening methodology documented and the implementation results.

2.1.3.2.3 Electrical and Instrumentation and Controls Screening

The audit team reviewed the screening implementation procedures and a selected sample of the system screening calculation results to ensure consistent application of the applicant's screening methodology. The applicant developed standard procedure EGR-NGGC-0505, "Electrical Component Screening and Aging Management Review for License Renewal," to define the process for performing screening of electrical components.

The applicant developed a generic list of electrical component types following the guidance in Appendix B to NEI 95-10, reviewed the EDB to identify electrical equipment that had electrical tag numbers for in-scope systems, and reviewed plant documentation, such as modifications, drawings, specifications, vendor manuals, DBDs, the UFSAR, and maintenance records, to identify electrical component types that were not identified by EDB tag numbers.

The electrical and I&C components were then grouped by type into commodity groups (e.g., circuit breakers, cables, sensors, elements). Component types with similar basic functions were grouped for the purpose of evaluation. Component types with unique design characteristics required unique groups and were evaluated separately. The applicant then documented the electrical commodity groups in an electrical screening calculation.

The screening calculation identified the commodity groups within which each electrical screening component type would be evaluated; the basic component groupings, such as similar function, design, materials of construction, aging effects, aging management practices, internal and external operation, environments, and operating experience; and the applicable design and licensing basis references for determining the commodity group.

The applicant reviewed the electrical commodity groups and identified those which met the scoping requirements of 10 CFR 54.4(a)(1-3). The components, within the commodity groups that met the scoping criteria, were reviewed to determine whether the components met the criteria of 10 CFR 54.21(a)(1). Commodity groups which contained long-lived, passive components, and were not replaced based on qualified life or specified time period, were determined to be subject to an AMR. The in-scope components identified as requiring an AMR were then compared to the GALL Report to ensure that differences are valid and justified.

The NRC audit team reviewed certain calculations used to implement standard procedure EGR-NGCC-0505. These calculations identified the electrical component commodity group for systems determined to be in scope in accordance with 10 CFR 54.4(a). The licensee calculations also documented which electrical components were active, passive, or long-lived.

The audit team reviewed a sample of electrical screening results assembled by the applicant, and discussed the process and results with the cognizant engineers who performed the review. The audit team did not identify any discrepancies between the screening methodology documented and the implementation results.

2.1.4 Evaluation Findings

The staff review of the information presented in Section 2.1 of the LRA, the supporting information in the RNP calculations and procedures, the information presented during the scoping and screening audit, and the applicant's responses to the staff's RAIs formed the basis of the staff's safety determination. The staff verified that the applicant's scoping and screening methodology, including its supplemental 10 CFR 54.4(a)(2) review which brought additional non-safety-related piping segments and associated components into the scope of license renewal, was consistent with the requirements of the Rule and the staff's position on the treatment of non-safety-related SSCs. On the basis of this review, the staff concludes that the applicant's methodology for identifying the SSCs within the scope of license renewal and the SCs requiring an AMR is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.2 Plant-Level Scoping Results

2.2.1 Summary of Technical Information in the Application

This section addresses the plant-level scoping results for license renewal. Pursuant to 10 CFR 54.21(a)(1), the applicant is required to identify and list SCs subject to an AMR. These are passive and long-lived SCs that are within the scope of license renewal.

In LRA Tables 2.2-1, 2.2-2, and 2.2-3, the applicant provided a list of the plant systems and structures and identified those that are within the scope of license renewal. The Rule does not require the identification of all plant systems and structures. However, providing such a list allows for a more efficient staff review. On the basis of the design-basis events considered in the plant's current licensing basis (CLB), other CLB information relating to non-safety-related systems and structures, and certain regulated events, the applicant identified those plant-level systems and structures within the scope of license renewal, as defined in 10 CFR 54.4(a). To verify that the applicant has properly implemented its methodology, the staff has focused its review on the implementation results to confirm that no plant-level systems and structures within the scope of license renewal have been omitted.

2.2.2 Staff Evaluation

In LRA Section 2.1, the applicant describes its methodology for identifying the SCs that are within the scope of license renewal and subject to an AMR. This methodology typically consists of a review of all plant SSCs to identify those that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4. From those SSCs that are within the scope of license renewal, an applicant will identify and list those SCs that are passive (i.e., that perform their intended functions without moving parts, or without a change in configuration or properties), and are long-lived (i.e., that are not replaced based on a qualified life or specified time period). The staff reviewed the scoping and screening methodology and provided its evaluation in Section 2.1 of this SER. The applicant documented the implementation of the methodology in LRA Sections 2.3 through 2.5. The staff's review of the applicant's implementation can be found in Sections 2.3 through 2.5 of this SER.

To ensure that the scoping and screening methodology described in LRA Section 2.1 was properly implemented, and that the SCs that are subject to an AMR were properly identified, the staff performed an additional review. The staff sampled the contents of the UFSAR based on the listing of systems and structures in LRA Tables 2.2-1, 2.2-2, and 2.2-3 to determine whether there were systems or structures that may have intended functions as defined by 10 CFR 54.4, but were not included within the scope of license renewal.

Scoping is performed to identify SSCs that perform intended functions within the scope of license renewal as required by 10 CFR 54.4. The RNP scoping process employed a multifaceted approach to ensure that the systems and structures meeting the requirements are identified. The LRA states that the process was designed to make optimum use of existing plant documents and databases to populate the list of systems and structures within the scope of the Rule.

In accordance with 10 CFR 54.4(a)(3), all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and SBO (10 CFR 50.63) are within the scope of license renewal. The LRA states that current licensing basis evaluations have been performed and documented which facilitate the identification of those SSCs credited in compliance with each of these regulations. It also states that, for these SSCs the system/structure level intended function is that it is relied upon in safety analyses or evaluations to demonstrated compliance with NRC requirements for the event in question.

In the LRA the applicant stated, and the staff agrees based on its review of the LRA and the UFSAR, that the scoping process to identify systems and structures relied upon and/or specifically committed to for fire protection, environmental qualification, pressurized thermal shock, anticipated transients without scram, and SBO is consistent with the criteria in 10 CFR 54.4(a)(3).

During this review, the staff decided that additional information and some clarification would be helpful in determining the completeness and acceptability of the application for a renewed license for the Robinson facility. Therefore, as part of the staff's review of the Robinson LRA a plant inspection was conducted and completed on April 4, 2003. An inspection report (50-261/03-08) documents the inspection findings, which were discussed in a public meeting on April 4, 2003, at the Hartsville Memorial Library, in Hartsville, South Carolina. The purpose of the inspection was to examine activities that support the application for a renewed license. The inspection examined procedures and records and conducted interviews with personnel regarding the process of scoping and screening plant equipment. The inspectors also performed visual inspections of accessible portions of systems to observe any effects of equipment aging. While following the NRC Manual Chapter 2516 and NRC Inspection Procedure 71002, the inspection did not identify any "findings" as defined in NRC inspection manual 0612. A followup inspection was conducted and completed by the same inspection team on June 27, 2003. An inspection report (50-261/03-09) documents the inspection findings, which was discussed in a public exit meeting on June 27, 2003. The purpose of this inspection was to review the implementation of the applicant's aging management programs (AMPs) and to revisit the inconsistencies observed and documented in the previous report (50-261/03-08).

The following is a summary of the inspection results outlined in the inspection reports.

The inspectors found three examples of inconsistencies between the LRA boundary drawings and calculations in the first inspection report (50-261/03-08) that supports the applicant's conclusions. To resolve this, the applicant wrote a plant action request (AR) to initiate corrective action to correct the inconsistencies. With respect to the auxiliary feed water system, the inspectors questioned why the deep well pumps and piping were not included in the scope of license renewal. The applicant's position is that this equipment does not provide a safety-related water source and therefore does not meet the LRA scoping criteria. This question was also asked in NRC staff's RAI number 2.3.3.8-1. The applicant responded to the RAI on April 28, 2003. The staff discusses the response in Section 2.3.3.8 of this SER and finds that the applicant's response requires further justification. This is still Open Item 2.3.3.8-1.

The inspectors also inspected the diesel fuel oil systems. The applicant's calculation (RNP-L/RA-0006) states that the Unit 1 fuel oil tanks and piping used to transfer oil to Unit 2 for long-term operation of the emergency diesel generators are in scope. However, the boundary drawings did not show the transfer piping as being in scope. The inspectors concluded that the piping should be in scope and included this discrepancy in the inspection report (50-261/03-08). The applicant acknowledged the inspector's comments and added the transfer piping in the boundary drawing and corrected the discrepancy which was confirmed in the inspection report (50-261/03-09).

The inspectors found during the first inspection that the applicant's calculation RNP-L/LR-0396 was intended to explain the process used for scoping and screening of Criterion 2 piping. Criterion 2 covers cases where non-safety-related piping (NSR) located in the vicinity of safety-related (SR) components might cause damage to SR components if they failed due to aging. However, calculation 0396 did not clearly describe the process or conclusions and inspectors identified several minor errors in the calculation. The inspectors stated in the inspection report (50-261/03-08) that the applicant should revise calculation 0396 to more clearly explain its process and conclusions. In the followup inspection in June, the inspectors concluded in the inspection report (50-261/03-09) that the applicant implemented appropriate corrective actions to revise the calculation 0396 and resolve previously identified problems.

2.2.3 Evaluation Findings

On the basis of this review, the staff concludes that the applicant has identified the systems and structures within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.3 Scoping and Screening Results: Mechanical Systems

This section addresses the mechanical systems' scoping and screening results for license renewal. The mechanical systems consist of the following (the SER sections are also provided):

- Reactor Systems

  Reactor Coolant System Piping (2.3.1.1)
  Reactor Coolant Pumps (2.3.1.2)
  Pressurizer (2.3.1.3)
  Reactor Pressure Vessel (2.3.1.4)
  Reactor Vessel Internals (2.3.1.5)
  Steam Generators (2.3.1.6)
  Reactor Vessel Level Instrumentation (2.3.1.7)

- Engineered Safety Feature Systems

  Residual Heat Removal System (2.3.2.1)
  Safety Injection System (2.3.2.2)
  Containment Spray System (2.3.2.3)
  Containment Air Recirculation Cooling System (2.3.2.4)
  Containment Isolation System (2.3.2.5)

- Auxiliary Systems

  Sampling Systems (2.3.3.1)
  Service Water System (2.3.3.2)
  Component Cooling Water System (2.3.3.3)
  Chemical and Volume Control System (2.3.3.4)
  Instrument Air System (2.3.3.5)
  Nitrogen Supply/Blanketing System (2.3.3.6)
  Radioactive Equipment Drain (2.3.3.7)
  Primary and Demineralized Water System (2.3.3.8)
  Spent Fuel Pool Cooling System (2.3.3.9)
  Containment Purge System (2.3.3.10)
  Rod Drive Cooling System (2.3.3.11)
  Heating Ventilation and Air Conditioning (HVAC) Auxiliary Building (2.3.3.12)
  HVAC Control Room Area (2.3.3.13)
  HVAC Fuel Handling Building (2.3.3.14)
  Fire Protection System (2.3.3.15)
  Diesel Generator System (2.3.3.16)
  Dedicated Shutdown Diesel Generator (2.3.3.17)
  Emergency Operations Facility/Technical Support Center (EOF/TSC) Security Diesel Generator (2.3.3.18)
  Fuel Oil System (2.3.3.19)

- Steam and Power Conversion Systems

  Turbine System (2.3.4.1)
  Electro-Hydraulic Control System (2.3.4.2)
  Turbine Generator Lube Oil System (2.3.4.3)
  Extraction Steam System (2.3.4.4)
  Main Steam System (2.3.4.5)
  Steam Generator Blowdown System (2.3.4.6)

Steam Cycle Sampling (2.3.4.7)
Feedwater System (2.3.4.8)
Auxiliary Feedwater System (2.3.4.9)
Condensate System (2.3.4.10)
Steam Generator Chemical Addition (2.3.4.11)
Circulating Water System (2.3.4.12)

10 CFR 54.21(a)(1) requires an applicant to identify and list SCs subject to an AMR. These are passive, long-lived SCs that are within the scope of license renewal. To verify that the applicant has properly implemented its methodology, the staff has focused its review on the implementation results. Such a focus allows the staff to confirm that there is no omission of mechanical system components that are subject to an AMR. If the review identifies no omission, the staff has the basis to find that the applicant has identified the mechanical system components that are subject to an AMR.

2.3.1 Reactor Systems

2.3.1.1 Reactor Coolant System Piping

2.3.1.1.1 Summary of Technical Information in the Application

The applicant describes the reactor coolant system (RCS) piping in LRA Section 2.3.1.1 and provides a list of components subject to an AMR in LRA Table 2.3-1.

The applicant's LRA and UFSAR contain the following description of the RCS.

The RCS consists of three similar heat transfer loops connected in parallel to the reactor vessel (RV). Each loop contains a steam generator (SG), a pump, loop piping, and instrumentation. The pressurizer surge line is connected to one of the loops. Auxiliary system piping connections into the reactor coolant piping are provided as necessary. The principal heat removal systems interconnected with the RCS are the steam and power conversion, safety injection (SI), and residual heat removal (RHR) systems. The RCS is dependent upon the SGs, and the steam, feedwater, and condensate systems for stored and residual heat removal from normal operating conditions to a reactor coolant temperature of approximately 350 °F.

The RCS transfers the heat generated in the core to the SGs where steam is generated to drive the turbine generator. Borated demineralized light water is circulated at the flow rate and temperature consistent with reactor core thermal hydraulic performance requirements. The water also acts as a neutron moderator and reflector and as a solvent for the neutron absorber used in chemical shim control. The RCS provides a boundary which contains the coolant under operating temperature and pressure conditions. During transient operation, the system's heat capacity attenuates thermal transients generated by the core or extracted by the SGs. The RCS accommodates coolant volume changes within the protection system criteria.

By appropriate selection of the inertia of the reactor coolant pump (RCP) (which affects pump coastdown), the thermal hydraulic effects which result from a loss of flow situation are reduced to a safe level. The layout of the system ensures natural circulation capability following a loss of flow to permit plant cooldown without overheating the core. Part of the system's piping is used by the emergency core cooling system to deliver cooling water to the core during a loss-of-coolant accident (LOCA).

Reactor coolant system piping consists of piping (including fittings, branch connections, thermal sleeves, tubing, and thermowells), pressure-retaining parts of valves, and bolted closures and connections. RCS piping is presented in two parts—(1) Class 1 piping and (2) non-Class 1 piping. The design code for the RCS piping is ASA B31.1-1955. The majority of RCS piping was designed to ASA B31.1; however, some small-bore piping was designed to American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III.

Class 1 piping includes the RCS main loop piping; pressurizer surge, spray, and safety and relief valve inlet lines; and vents, drains, and instrument lines. Portions of ancillary systems attached to the RCS are also Class 1. Ancillary systems attached to the RCS include the SI system, RHR system, chemical and volume control system (CVCS), and primary sampling system.

Several non-Class 1 piping components in the RCS are within the scope of license renewal for RNP. These include (1) the pressurizer relief tank (PRT), (2) the pressurizer relief and safety valve discharge lines to the PRT, (3) auxiliary lines supporting RCS and PRT functions including containment isolation valves in those lines, and (4) reactor vessel level instrumentation lines downstream of Class 1 boundary bellows.

The PRT, located inside containment, normally contains water at or near ambient containment conditions in a predominantly nitrogen atmosphere. Steam is discharged from relief and safety valves of the RCS into the PRT where it is condensed and cooled by mixing with the water. The PRT also collects leakage and liquid from various system pressure relief valves located inside the containment. The PRT was designed to the ASME Boiler and Pressure Vessel Code, Section III, Class C. To reduce the likelihood of PRT overpressurization following a discharge, the PRT is equipped with a spray to add cooling water and a drain to the waste disposal system (WDS) to remove excess heated water. The PRT is also equipped with two rupture discs that relieve pressure to the containment vessel (CV) at approximately 100 psig. The rupture discs are designed to pass 900,000 lb/hr of saturated steam.

The PRT size is 1300 ft^3 with a design temperature and pressure of 340 °F and 100 psig respectively. The PRT is piped to the pressurizer safety and power-operated relief valves (PORVs) by a 12-inch line. The PRT is normally filled to about 70 percent with primary water and also has approximately 3 psig nitrogen atmosphere in it. A nitrogen regulator outside containment maintains this pressure in the tank along with the ability to vent the PRT to the vent header. Primary water may be added to the tank by use of the primary water pumps and valves. Water may be pumped from the tank by utilizing the "B" reactor coolant drain tank (RCDT) pump and valves or gravity drained to the containment sump.

2.3.1.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.1, UFSAR Sections 5.1 and 5.4.3, and Drawing No. 5739-1971-LR (two sheets)—Reactor Coolant System Flow Diagram to determine whether there is reasonable assurance that the RCS piping components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as subject to an AMR to determine if any components were omitted.

Since the reactor coolant system piping is largely composed of components that form the pressure boundary, and that carry the reactor coolant to the reactor vessel and the steam generators, the staff's review was centered upon identification of the components that would be required to be within scope, as safety related equipment that perform the functions described in 10 CFR 54.4(a)(1). The staff's review of long-lived, passive components in the reactor coolant system excluded components that are periodically replaced, such as seals and gaskets, and active components, such as the moving parts in pumps and valves.

Non-safety-related components and piping were also considered (1) if they could fail in such a manner as to prevent other systems and components from completing any of the functions described in 10 CFR 54.4(a)(1), or (2) if they are required for compliance with the regulations for fire protection, environmental qualification, pressurized thermal shock protection, anticipated transients without scram protection, or SBO protection listed in 10 CFR 54.4(a)(3).

The applicant has included the PRT in the pressure-retaining boundary even though this pressure-retaining boundary will be maintained only until the tank's rupture disks give way, as designed, at about 100 psi. This is acceptable to the staff, since the PRT could play a limited role in supporting some of the functions described in 10 CFR 54.4(a)(1), particularly in situations where the rupture disks remain intact.

2.3.1.1.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the RCS piping that is within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified RCS piping that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.2 Reactor Coolant Pumps

2.3.1.2.1 Summary of Technical Information in the Application

The applicant describes the reactor coolant pumps (RCPs) in LRA Section 2.3.1.2.

The applicant's LRA and UFSAR contain the following description of the RCPs. The RCPs provide the motive force for circulating the reactor coolant through the reactor core, piping, and SGs. Each reactor coolant loop contains a vertical single-stage centrifugal pump which employs a controlled leakage seal assembly. Reactor coolant is pumped by the impeller attached to the bottom of the rotor shaft. The coolant is drawn up through the impeller, discharged through passages in the diffuser and out through a discharge nozzle in the side of the casing. The motor-impeller can be removed from the casing for maintenance or inspection without removing the casing from the piping.

All parts of the pumps in contact with the reactor coolant are austenitic stainless steel or equivalent corrosion-resistant materials. The RNP RCP casings were designed in accordance with ASME Boiler and Pressure Vessel Code, Section III, Class A.

Component cooling water (CCW) is supplied to the motor bearing cooler and the thermal barrier cooling coil. The squirrel cage induction motor driving the pump is air cooled and has oil lubricated thrust and radial bearings. A water-lubricated bearing provides radial support for the pump shaft. A flywheel and an antireverse rotation device are located at the top of the RCP motor. The flywheel provides additional inertia to increase the RCP coastdown time, thereby reducing the consequences of a LOCA. The antireverse rotation device prevents backflow, which may occur during LOCA, from turning the RCP in the reverse direction.

The portion of the RCP rotating element above the pump coupling, including the electric motor and the flywheel, is not subject to an AMR in accordance with 10 CFR 54.21(a)(1)(i). RCP seals are not subject to an AMR because (1) seal leakoff is closely monitored in the control room, and high leakoff flow rate is alarmed as an abnormal condition requiring corrective action, and (2) the RCP seal package and its constituent parts are periodically overhauled on a schedule established by the Preventive Maintenance Program; the seals are inspected and parts are replaced, as required.

Plant operating experience (OE) with pump seal performance has demonstrated the effectiveness of these activities.

Each RCP is supported on a three-legged structural system consisting of three connected columns fabricated of carbon steel members, structural sections, and pipe. Provisions for limited movement of the structure in any horizontal direction to accommodate piping expansion are accomplished with a sliding "Lubrite" base plate arrangement and a system of tie rods and anchor bolts which restrain the structure from movement beyond the calculated limits. A sliding slot at the top of the support structures permits radial thermal growth of the pumps during heatup.

2.3.1.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.2 and UFSAR Section 5.4.1 to determine whether there is reasonable assurance that the RCP components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as subject to an AMR to determine if any components were omitted.

The reactor coolant pumps contain several important components that would not be required to be included in the license renewal scope, since they are not passive, long-lived components. For example, the pump seals are not long-lived, since they are periodically overhauled or replaced, according to Robinson's Preventive Maintenance Program. Other components, however, such as the pump casings and supports, are included in the scope. The pump casings, for example, are passive, long-lived components that comprise part of the reactor coolant system pressure boundary. As such, they are required by 10 CFR 54.4(a)(1) and 10 CFR 54.21(a)(1) to be included in the license renewal scope.

In the review of the reactor coolant pumps, the applicable controlling regulation is proved to be 10 CFR 54.4(a)(1), since its provisions apply directly to the great majority of the reactor coolant pump system components. The pump casings, for example, are in the reactor coolant system pressure boundary. Generally, the reactor coolant pumps may be considered to be under constant test or surveillance, since they are normally in operation. Failure of a pump would be immediately detected, and would likely initiate automatic reactor protection system action, such as a reactor trip. In fact, reactor coolant pump failures are addressed in Chapter 15 of the UFSAR. For the purposes of license renewal, the reactor coolant pump failures of concern would be failures in the passive, long-lived components, such as the pump casings, which would be seen as reactor coolant leaks or breaks. These are also addressed in Chapter 15 of the UFSAR.

2.3.1.2.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the RCP components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the RCP components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.3 Pressurizer

2.3.1.3.1 Summary of Technical Information in the Application

The applicant describes the pressurizer in LRA Section 2.3.1.3 and provides a list of components subject to an AMR in LRA Table 2.3-1.

The applicant's LRA contains the following description of the pressurizer.

The pressurizer is a vertical cylindrical vessel containing electric heaters in its lower head and a water spray nozzle in its upper head. Sources of heat to the RCS are interconnected by piping to the pressurizer with no intervening isolation valves; the pressurizer lower head is connected to the RCS by the surge line. Pressure relief protection for the RCS is provided on the pressurizer. Overpressure protection consists of three code safety valves and two PORVs. Piping attached to the pressurizer is Class 1 up to and including the safety and relief valves.

The pressurizer was designed and fabricated in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Class A. The pressurizer is constructed of carbon steel with internal surfaces clad with austenitic stainless steel. The heaters are sheathed in austenitic stainless steel. The pressurizer vessel surge nozzle is protected from thermal shock by a thermal sleeve. A thermal sleeve also protects the pressurizer spray nozzle.

The pressurizer maintains the required reactor coolant pressure during steady-state operation, limits the pressure changes caused by coolant thermal expansion and contraction during normal load transients, and prevents the pressure in the RCS from exceeding the design pressure.

The pressurizer contains replaceable direct immersion heaters, multiple safety and relief valves, a spray nozzle and interconnecting piping, valves and instrumentation. The electric heaters located in the lower section of the vessel maintain the pressure of the RCS by keeping the water and steam in the pressurizer at saturation temperature corresponding to the system pressure. Three pressurizer heater banks (one control and two backup) with a total design capacity of 1300 kilowatts (kW) are installed. A minimum total capacity of 800 kW is required for normal operating conditions. A minimum of 125 kW of heater capacity is capable of being powered from emergency power supplies. This capacity is sufficient to maintain the RCS near normal operating pressure and to aid natural circulation. This is automatically tripped off from the emergency bus in the event of an SI signal to prevent overloading of the diesel generators (DGs).

The pressurizer is designed to accommodate positive and negative surges caused by load transients. The surge line which is attached to the bottom of the pressurizer connects it to the hot leg of a reactor coolant loop. During a positive surge, caused by a decrease in plant load, the spray system, which is fed from the cold leg of a coolant loop, condenses steam in the pressurizer to prevent the pressurizer pressure from reaching the set point of the PORVs. Power-operated spray valves on the pressurizer limit the pressure during load transients. In addition, the spray valves can be operated manually by a switch in the control room. A small continuous spray flow is provided to assure that the pressurizer liquid is homogeneous with the coolant and to prevent excess cooling of the spray and surge line piping.

2.3.1.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.3 and UFSAR Section 15.6.3.2.1 to determine whether there is reasonable assurance that the pressurizer SSCs within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as subject to an AMR to determine if any components were omitted.

The pressurizer, a safety-related, in-scope component, contains a spray head, a non-safety-related component, which the applicant proposes to exclude from the license renewal scope.

The spray head distributes normal and auxiliary pressurizer spray water into the pressurizer steam bubble, which tends to depressurize the pressurizer, and hence the RCS. Since the normal and auxiliary pressurizer sprays are not safety systems, they cannot be relied upon to function during any of the Chapter 15 accident analyses, unless, in some postulated analysis cases, pressurizer spray could have an aggravating effect upon the transient results (e.g., by delaying a high pressurizer pressure reactor trip).

However, Section 15.6.3.2.1 of the UFSAR mentions the means by which the RCS might be depressurized during a steam generator tube rupture (SGTR) event. The UFSAR lists, "in order of preference: (1) normal pressurizer spray; (2) pressurizer power operated relief valves (PORVs); (3) auxiliary pressurizer spray, and; (4) balancing charging/letdown or using unaffected steam generators for cooldown/depressurization." Normal and auxiliary pressurizer sprays are two of the four listed means of reducing the primary side coolant pressure and ending the primary to secondary side tube break flow. Although the spray flow rates are not determined according to any performance requirements set by the SGTR event, the normal and auxiliary sprays constitute two of the four listed depressurization methods. If, for some reason, the spray head fails in such a way as to block all spray flow, then normal and auxiliary sprays would become unavailable for cooldown and depressurization following an SGTR event.

The spray head is a passive component that presents many parallel flow paths for spray delivery. To end the spray flow, all the flow paths must be blocked, more or less simultaneously. This is characteristic of a common mode fault. Furthermore, this fault must occur just when the spray system is required to perform its function. If the failure occurs before that time, then it would be detected when the normal spray flow is terminated and the pressurizer heaters reduce their compensating heat output.

If the spray head were to fail by falling off the end of its supply line, then the spray water would be still be available, but as a stream, not a fine spray. There would still be some, although diminished, depressurizing effect. This would also be soon detected and corrected.

There do not appear to be any other types of failures in the spray head that could impair or disable the spray function.

Therefore, it seems that inclusion of the pressurizer spray head in the license renewal scope would not be required by either 10 CFR 54.4(a)(1) or by 10 CFR 54.4(a)(3).

However, the staff believes that inclusion of the pressurizer spray head in the license renewal scope under the terms of 10 CFR 54.4(a)(2) merits serious consideration, since the pressurizer spray head is a non-safety-related component that is completely enclosed by a Class 1 component. According to 10 CFR 54.4(a)(2), plant systems, structures, and components that are within the scope of the license renewal application are, ... "All non-safety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1) (i), (ii), or (iii) of this section." Paragraphs (a)(1) (i), (ii), and (iii) address the integrity of the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, and the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures, respectively. This issue was designated as Confirmatory Item No. 2.3.1.3-1.

If the pressurizer spray head were to degrade or crack, and shed one or more pieces of the head, then these pieces could become loose parts inside the pressurizer. During a pressurization transient, such as a loss or normal feedwater event, or a load rejection, the power-operated relief valves or even the code safety valves might open. A loose part inside the pressurizer might be drawn into the throat of a power-operated relief valve or a code safety valve, and prevent the pressurizer pressure relieving valves from protecting the integrity of the reactor coolant pressure boundary. Depending upon the size and position of the loose part inside the valve throat, the loose part might prevent the valve from reseating properly, and thereby transform a pressurization event into a depressurization event.

The possibility that such loose parts might be generated and that they might prevent certain safety functions of the pressurizer components is not, by itself, sufficient to require that the pressurizer spray head be included in the license renewal scope. There must be some basis, in operating experience, that such a scenario could be reasonably expected to occur sometime during the 20-year license extension, following a 40-year aging period. To date, there have been no recorded instances of this type of failure. Therefore, without an experiential basis, the requirements of 10 CFR 54.4(a)(2) would not be construed to mandate the inclusion of the pressurizer spray head in the license renewal scope.

The pressurizer spray head was temporarily excluded from the license renewal scope, as Confirmatory Item No. 2.3.1.3-1, pending a review of industry-wide and plant-specific operational experience by CP&L to confirm that failure of the pressurizer spray head could not prevent accomplishment of any of the functions identified in 10 CFR 54.4(a)(1). CP&L responded that their review indicated that the hypothetical failure had not been previously experienced. Therefore, the staff concludes that 10 CFR 54.4(a)(2) does not require the inclusion of the pressurizer spray head in the license renewal scope for the H.B. Robinson plant, and the confirmatory item is closed.

2.3.1.3.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. The staff concluded that it was not necessary to include the pressurizer spray head in the license renewal scope, to meet the requirements of either 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3).

Furthermore, the possibility of a failure in the pressurizer spray head, affecting the functioning of the PORVs or pressurizer safety valves was postulated, and considered under the terms of 10 CFR 54.4(a)(2). In accordance with the NEI guidelines, the staff requested CP&L to provide information to show that the hypothetical failure has not been experienced at H.B. Robinson or at other plants. The applicant surveyed plant-specific and industry-wide operating experience, and found that there were no known occurrences of the postulated failure scenario. Therefore, the staff concludes that inclusion of the pressurizer spray head in the license renewal scope is not required by 10 CFR 54.4(a)(2), and that confirmatory item no. 2.3.1.3-1 is closed.

2.3.1.4 Reactor Pressure Vessel

2.3.1.4.1 Summary of Technical Information in the Application

The applicant describes the reactor pressure vessel in LRA Section 2.3.1.4 and provides a list of components subject to an AMR in LRA Table 2.3-1.

The applicant's LRA and UFSAR contain the following description of the reactor pressure vessel.

The RV consists of the cylindrical vessel shell, lower vessel head, closure head, nozzles, interior attachments, and associated pressure-retaining bolting. The vessel is fabricated of a low-carbon alloy steel with austenitic stainless steel cladding on all surfaces exposed to the reactor coolant fluid. Coolant flow enters the RV through three inlet nozzles in a plane just below the vessel flange and above the core. The coolant flows downward through the annular space between the vessel wall and the core barrel into a plenum at the bottom of the vessel where it reverses direction, passes up through the core into the upper plenum, and then flows out of the vessel though three exit nozzles located on the same plane as the inlet nozzles. The RPV was designed according to the 1965 Edition of the ASME Boiler and Pressure Vessel Code, Section III, Class A.

2.3.1.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.4 and UFSAR Section 5.3 to determine whether there is reasonable assurance that the reactor pressure vessel SSCs within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

The reactor pressure vessel components that would be subject to an aging management review are listed in Table 2.3-1 of the LRA. Many of these components, such as vessel heads and flanges, and pressure vessel penetrations for control rod drives and for instrument lines, are considered to be in the pressure-retaining boundary. As such, they would be subject to the requirements of 10 CFR 54.4(a)(1). The applicant has also included the cladding in various regions of the pressure vessel as separate components.

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as subject to an AMR to determine if any components were omitted.

The staff agrees with the applicant's identification of the pressure vessel and its associated pressure boundary components as items that should be part of the license renewal scope.

2.3.1.4.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs or components that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the reactor pressure vessel SSCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the reactor pressure vessel SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.5 Reactor Vessel Internals

2.3.1.5.1 Summary of Technical Information in the Application

The applicant describes the RV internals in LRA Section 2.3.1.5 and provides a list of components subject to an AMR in LRA Table 2.3-1.

The applicant's LRA and UFSAR contain the following description of the reactor vessel internals.

The RV internals are designed to support, align, and guide the core components and to support and guide in-core instrumentation. The RV internals consist of two basic assemblies—an upper internals assembly that is removed during each refueling operation to obtain access to the reactor core, and a lower internals assembly that can be removed, if desired, following a complete core unload.

The lower internals assembly is supported in the vessel by resting on a ledge in the vessel head-mating surface and is closely guided at the bottom by radial support/clevis assemblies. The upper internals assembly is clamped at this same ledge by the reactor vessel head. The bottom of the upper internals assembly is closely guided by the core barrel alignment pins of the lower internals assembly.

The lower internals comprise the core barrel, thermal shield, core baffle assembly, lower core plate, intermediate diffuser plate, bottom support plate, and supporting structures. The upper internals package (upper core support structure) is a rigid member composed of the top support plate and deep beam sections, support columns, control rod guide tube assemblies, and the upper core plate. Upon upper internals assembly installation, the last three parts are physically located inside the core barrel.

The in-core instrumentation includes in-core flux guide thimbles to permit the insertion of movable detectors for measurement of the neutron flux distribution within the reactor core. Movable miniature neutron flux detectors are available to scan the active length of selected fuel assemblies to provide remote reading of the relative three-dimensional flux distribution. The thimbles are inserted into the reactor core through guide tubes, or conduits, extending from the bottom of the RV through the concrete shield area and then up to a thimble seal table. Since the movable detector thimbles are closed at the leading (reactor) end, they are dry inside. The thimbles thus serve as a pressure barrier between the reactor coolant pressure and the atmosphere. Mechanical seals between the retractable thimbles and the conduits are provided at the seal table.

2.3.1.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.5 and UFSAR Sections 3.9.5 and 7.7.1.5 to determine whether there is reasonable assurance that the RV internals SSCs within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as subject to an AMR to determine if any components were omitted.

The reactor vessel internals that would be subject to an aging management review are listed in Table 2.3-1 of the LRA. Most of these components are identified as components that provide structural support to safety-related components. They can provide, for example, some of the structural support needed to maintain a coolable core geometry during a design-basis loss-of-coolant-accident.

Unlike many other long-lived, passive components, certain reactor internals are normally moved (i.e., removed and set aside) to permit the movement of fuel assemblies during refueling. This provides periodic opportunities to detect and remedy aging-related problems that might affect these reactor vessel internals. The staff, however, does not judge this to be sufficient to exempt such components from aging management requirements.

2.3.1.5.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs, or components that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the RV internals SSCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the RV internals SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.6 Steam Generators

2.3.1.6.1 Summary of Technical Information in the Application

The applicant describes the SGs in LRA Section 2.3.1.6 and provides a list of components subject to an AMR in LRA Table 2.3-1.

The applicant's LRA contains the following description of the steam generators.

The SGs remove heat from the RCS by converting feedwater into steam. The SGs provide sufficient capacity to remove heat during normal operations and following postulated accidents and transients. An integral flow restrictor limits the flow rate of steam from an SG following a postulated steam line break accident. SG level instrumentation is provided to assure the heat removal capability is maintained following an accident.

Three SGs are installed, one in each of the three RNP reactor coolant loops. Each SG is a vertical shell-and-tube heat exchanger that transfers heat from a single-phase fluid at high temperature and pressure (the reactor coolant) in the tube side, to a two-phase (steam-water) mixture at lower temperature and pressure in the shell side.

Reactor coolant enters and exits the tube side of each SG through nozzles located in the lower hemispherical head. The RCS fluid flows through inverted U-tubes connected to the tubesheet. The lower head is divided into inlet and outlet chambers by a vertical partition plate extending from the lower head to the tubesheet. The steam-water mixture is generated on the secondary, or shell side, and flows upward through moisture separators and dryers to the outlet nozzle at the top of the vessel providing essentially dry, saturated steam. Manways and inspection ports are provided to permit access to both sides of the lower head and to the U-tubes and moisture-separating equipment on the shell side of the SGs.

The SG support system includes hydraulic snubbers. The snubbers are considered to be structural components; however, portions of the hydraulic equipment for each SG (manifold, hydraulic control unit, flex hoses, piping, reservoir) are subject to an AMR to assure that their pressure boundary integrity is maintained.

Lower assemblies of the SGs, including the lower shell, tubes, and tubesheet, were replaced in 1984.

2.3.1.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.6 and UFSAR Sections 5.4.2 and 10.3 to determine whether the SG SSCs are within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The SG, a safety-related, in-scope component, contains a feedring, a non-safety-related component, which the applicant proposes to exclude from the license renewal scope.

The feedring distributes main feedwater into the SG shell side, through a number of J-tubes mounted along the upper surface of the feedring. The feedring is normally filled with feedwater, up to a level that is higher than the feedring itself (i.e., to a level inside the J-tubes). This arrangement prevents the formation of steam inside the feedring, which minimizes the possibility of water hammer in the feedwater system. The same feedring distributes auxiliary feedwater (AFW) during startup and shutdown operations and during certain accidents and transients.

The feedring is not classified as a safety-related component. However, the feedring delivers and distributes AFW, which is required for the removal of decay heat during shutown and following certain accidents. The feedring can fail to perform its distribution function (e.g., by clogging of some J-tubes) without materially affecting the overall primary to secondary heat transfer rate in the SG, provided that all the main or AFW flow continues to be delivered. Full flow, if not uniformly distributed, would still be adequate in the context of accident analyses, to demonstrate compliance with the applicable acceptance criteria. Therefore, clogging, or other problems that prevent the uniform distribution of main or AFW flowing through the feedring, would not be expected to affect normal functioning of by the SG or associated components.

If the feedring is not required to remain functional during and following design-basis events to ensure the accomplishment of the safety-related functions listed in 10 CFR 54.4(a)(1), then 10 CFR 54.4(a)(1) would not require the feedring to be part of the license renewal scope.

The feedring is also subject to the requirements of 10 CFR 54.4(a)(2) and 10 CFR 54.4(a)(3). 10 CFR 54.4(a)(2) can be summed up by stating that, if a non-safety-related SSC cannot fail in such a way as to prevent the satisfactory accomplishment of the functions listed in 10 CFR 54.4(a)(1), then it need not be included in the license renewal scope. The requirements of 10 CFR 54.4(a)(3) apply to all SSCs that are relied upon to perform functions necessary to comply with regulations pertaining to fire protection (FP), environmental qualification (EQ), pressurized thermal shock (PTS), anticipated transients without scram (ATWS), and station blackout (SBO).

10 CFR 54.4(a)(2) requires the feedring to be included in the license renewal scope if it can fail in a way that prevents the accomplishment of any of the functions listed in 10 CFR 54.4(a)(1). Example: if there is leak or jet from the feedring that pours cold auxiliary feedwater onto the steam generator tubes, during a transient in which reduced secondary side inventory exposes the tubes, then there is a risk of thermal shock to the tubes and tube rupture. Example: if the feedring begins to degrade and crack, and a piece of the feedring or J-tube falls onto the tubesheet, it might damage the tubesheet area around the tube penetrations. Example: a small piece might break off the feedring during an SG depressurization event, such as the spurious opening of a safety or dump valve. If the piece is small enough to pass through the perforated deck plate, through the steam separators, and through the flow element, then it could possibly lodge in the valve throat and damage or prevent the proper functioning of the valve. Such possibilities, though not likely, indicate that certain failures in the feedring, which could prevent the safety-related functions of the surrounding SG, would mandate the inclusion of the feedring in the scope of license renewal, under the terms of 10 CFR 54.4(a)(2).

The possibility that such loose parts might be generated and that they might prevent the accomplishment of certain safety functions of the steam generator is not, by itself, sufficient to require that the feedring be included in the license renewal scope. There must be some basis, in operating experience. The NEI guidelines indicate that the hypothetical failure (the loose part scenario) need not be considered if it has not been previously experienced.

In response to a staff request for further information in RAI 2.3.1.6-1, RNP surveyed operating history experience compiled by the World Association of Nuclear Operators (WANO) and the Institute of Nuclear Power Operations (INPO), and found that there were no recorded instances of this type of failure. They did find, however, instances wherein J-tubes were replaced, due to corrosion problems, and an instance wherein there was direct leakage from the feedring. These can be considered to be preconditions to the loose part scenario. Therefore, the staff believes that the feedring should be within the license renewal scope. In a letter dated September 16, 2003 (ADAMS accession no. ML032650884), the applicant agreed to include the steam generator feedrings in the scope of the license renewal application. The steam generator feedrings and their associated aging management program are discussed in Section 3.1.2.2.14 of this report.

2.3.1.6.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. On the basis of this review, the staff indicated to the applicant that the SG feedrings should be included in the scope of license renewal, under the requirements of 10 CFR 54.4(a)(2), since there is a possibility that certain failures in the feedrings could lead to prevention of one or more of the safety-related functions of 10 CFR 54.4(a)(1). The applicant included the steam generator feedrings in the scope of the license renewal application. Therefore, the staff concludes that the applicant has adequately identified the SG SSCs that are within the scope of license renewal, and subject to an AMR, as required by 10 CFR 54.4(a).

2.3.1.7 Reactor Vessel Level Instrumentation

2.3.1.7.1 Summary of Technical Information in the Application

The applicant describes the RV level instrumentation in LRA Section 2.3.1.7.

The applicant's LRA contains the following description of the RV instrumentation.

A core cooling instrumentation system is provided to detect the approach to inadequate reactor core cooling and assess the adequacy of responses taken to restore core cooling. The system consists of three subsystems—reactor vessel level instrumentation system (RVLIS), core exit thermocouple system (CETS), and the core cooling monitor system (CCMS). Portions of the RVLIS consist of mechanical components that are part of the RCS pressure boundary or part of the containment pressure boundary.

2.3.1.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.7 to determine whether there is reasonable assurance that the RV-level instrumentation SSCs within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

The reactor vessel instrumentation components that would be subject to an aging management review are listed in Table 2.3-1 of the LRA. Many of these components, such as pressure vessel penetrations for instrument lines, are considered to be in the pressure-retaining boundary. As such, they would be subject to the requirements of 10 CFR 54.4(a)(1). The table does not specifically identify the instrumentation lines that are part of the reactor vessel instrumentation systems (e.g., RVLIS, CETS, and CCMS). Instead, instrumentation lines are treated as vessel penetrations and elements of the pressure-retaining boundary. For purposes of license renewal and aging management, the staff judges this to be a reasonable approach.

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

2.3.1.7.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the RV level instrumentation SSCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the RV level instrumentation SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.8 Evaluation Findings

On the basis of this review, the staff concludes that the applicant has adequately identified the RCSs and components that are within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a), and that the applicant has adequately identified the RCS components that are subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

2.3.2 Engineered Safety Features Systems

2.3.2.1 Residual Heat Removal System

2.3.2.1.1 Summary of Technical Information in the Application

The applicant describes the RHR system in LRA Section 2.3.2.1 and provides a list of components subject to an AMR in LRA Table 2.3-2.

The applicant's LRA and UFSAR contain the following description of the RHR system.

The RHR system delivers borated water to the RCS during the injection phase of a design-basis accident (DBA). Following a LOCA, the RHR system cools and recirculates water that is collected in the containment recirculation sump and returns it to the reactor coolant, containment spray, and SI systems to maintain reactor core and containment cooling functions. In addition, during normal plant operations, the RHR system removes residual and sensible heat from the core during plant shutdown, cooldown, and refueling operations. The RHR system is used to achieve cold shutdown conditions following a postulated fire in accordance with 10 CFR 50, Appendix R, requirements.

The RHR system is in the scope of license renewal, because it contains SCs that are safety related and are relied upon to remain functional during and following design-basis events, SCs that are part of the Environmental Qualification Program, and SCs that are relied upon during postulated fires and SBO events.

2.3.2.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.1 and UFSAR Sections 5.4.4 and 6.3 to determine whether there is reasonable assurance that the RHR system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.3-2 of the LRA lists RHR system components that are to be included in the license renewal scope. These components are included because they are safety-related equipment that are required to operate during and after design-basis accidents, or they are relied upon for FP or in SBO events. All the listed components are in the pressure-retaining boundary. RHR system components are generally required to be included in the license renewal scope because they perform the functions addressed by 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3).

2.3.2.1.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the RHR system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the RHR system that are subject to an AMR, as required by 10 CFR54.21(a)(1).

2.3.2.2 Safety Injection System

2.3.2.2.1 Summary of Technical Information in the Application

The applicant describes the SI system in LRA Section 2.3.2.2 and provides a list of components subject to an AMR in LRA Table 2.3-3.

The applicant's LRA and UFSAR contain the following description of the SI system.

Following a postulated DBA, adequate emergency core cooling is provided by the SI system, whose components operate in three modes—passive accumulator injection, active SI, and residual heat removal recirculation. The primary purpose of the system is to deliver cooling water to the reactor core in the event of a LOCA. This limits the fuel cladding temperature and thereby ensures that the core will remain intact and in place, with its heat transfer geometry preserved. The system also provides a source of borated water for reactivity control.

The SI system is in the scope of license renewal, because it contains SCs that are safety related and are relied upon to remain functional during and following design-basis events, SCs that are part of the Environmental Qualification Program, and SCs that are relied upon during postulated fires and SBO events.

2.3.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.2 and UFSAR Section 6.3 to determine whether there is reasonable assurance that the SI system SSCs within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The Safety Injection System components that are to be included in the license renewal scope are listed in Table 2.3-3 of the LRA. Like the RHR system, these components are safety-related equipment, and many are also in the pressure-retaining boundary. The sump screens and supports are also among the in-scope components. The SI system is required to function during and after design-basis events and SBOs. Its components are generally required to be included in the license renewal scope because they perform the functions addressed by 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3).

2.3.2.2.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the SI system SSCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the SI system SSCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.3 Containment Spray System

2.3.2.3.1 Summary of Technical Information in the Application

The applicant describes the containment spray system (CSS) in LRA Section 2.3.2.3 and provides a list of components subject to an AMR in LRA Table 2.3-4.

In conjunction with the containment air recirculation cooling system, the first intended function of the CSS is to limit the temperature and pressure within the containment during DBAs to less than the design values for the containment. These two separate, full-capacity systems use diverse engineered features to achieve their intended containment heat removal functions, thereby providing an additional degree of redundancy. A second intended function performed by the CSS is to remove elemental iodine from the containment atmosphere, should it be released during an accident, in order to satisfy the limits of 10 CFR Part 100.

The CSS consists of two trains. Each train includes a pump, pump cooler, associated piping and valves, spray headers, and spray nozzles. To support the intended function of removing elemental iodine from the containment atmosphere, the flow from each train of the CSS is mixed with sodium hydroxide from the containment spray additive tank via eductors. Immediately following a design-basis LOCA the CSS would normally be operated in the injection mode, taking suction from the borated inventory provided by the refueling water storage tank (RWST). If necessary, following the switchover to the recirculation mode of operation, the containment spray system would take suction from the containment recirculation sump, utilizing the residual heat removal system heat exchangers to transfer heat from the containment atmosphere to secondary plant cooling systems.

In LRA Table 2.3-4, the applicant identifies eight component types of the CSS as being within the scope of license renewal and subject to an AMR.

(1) closure bolting
(2) containment vessel spray pump seal cooler heat exchanger tubing
(3) containment vessel spray pump seal heat exchanger shell and cover
(4) containment vessel spray pump(s)
(5) eductors
(6) flow orifices/elements
(7) spray additive tank
(8) valves, piping, tubing, and fittings

The LRA further identifies that each of these eight component types provides a pressure-boundary intended function. Additionally, the containment vessel (CV) spray pump seal cooler heat exchanger tubing is identified as providing a heat-transfer intended function; eductors and flow orifices/elements are identified as providing a throttling function; and valves, piping, tubing, and fittings are identified as providing the intended function of structural support.

2.3.2.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.3 and UFSAR Section 6.2.2 to determine whether there is reasonable assurance that the applicant has identified the components of the containment spray system within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1). In its review of this section, the staff also reviewed Sections 2.3.2.1 and 2.3.2.2 of the LRA to determine whether there is reasonable assurance that the applicant has applied the license renewal scoping and screening criteria to components primarily associated with the RHR and SI systems (e.g., residual heat removal heat exchangers, the RWST, and containment sump screens) that are also relied upon to support the intended functions of the CSS in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

In the performance of its review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The staff's review of the applicant's scoping results did not identify the omission of any components needed to support the performance of the two intended functions of the CSS, including necessary components that the LRA treats as belonging to the RHR and SI systems.

Generally, the applicant adequately identified in LRA Table 2.3-4 those passive, long-lived components of the CSS considered to be within the scope of license renewal. However, the NRC staff identified three instances where passive, long-lived components identified as being within scope did not appear to be listed in LRA Table 2.3-4 as being subject to an AMR. On February 11, 2003, the NRC staff issued RAIs to the applicant concerning these three instances to determine whether the applicant had properly applied the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs and the applicant's responses, dated April 28, 2003, are described below.

In RAI 2.3.2.3-1, the NRC staff requested that the applicant identify whether the two vacuum breakers protecting the containment spray additive tank from excessive external pressure (i.e., SI-899D and SI-899E) are subject to an AMR in accordance with 10 CFR 54.21(a)(1). Although the applicant indicated that the vacuum breakers are within the scope of license renewal, the vacuum breakers are not included in LRA Table 2.3-4 explicitly, nor is it clear that they are subsumed into one of the component groups listed in LRA Table 2.3-4. The applicant's response to this RAI states that vacuum breakers SI-899D and SI-899E are included in the component group entitled "Valves, Piping, Tubing, and Fittings," which is an existing entry in LRA Table 2.3-4. The staff finds the applicant's response to RAI 2.3.2.3-1 to be acceptable because the applicant identified that the in-scope vacuum breakers are subject to an AMR in accordance with the criteria set forth in 10 CFR 54.21(a)(1). Therefore, staff considers this RAI to be closed.

In RAI 2.3.2.3-2, the NRC staff requested that the applicant identify whether the containment spray header nozzles are subject to an AMR in accordance with 10 CFR 54.21(a)(1). Although the applicant indicated that the spray nozzles are within the scope of license renewal, the nozzles are not included in LRA Table 2.3-4 explicitly, nor is their intended function of inducing spray flow attributed to any component group listed in LRA Table 2.3-4. The applicant's response to this RAI states that the containment spray nozzles are included in the component group entitled "Valves, Piping, Tubing, and Fittings," which is an existing entry in LRA Table 2.3-4. The applicant further explained its position that both the functions of providing a pressure boundary and inducing spray flow are encompassed in the pressure-boundary intended function attributed to this component group in LRA Table 2.3-4. The staff finds the applicant's response to RAI 2.3.2.3-2 to be acceptable because the applicant identified that the containment spray nozzles are subject to an AMR in accordance with the criteria set forth in 10 CFR 54.21(a)(1), and that inducing spray flow is included in the intended function of this component group. Therefore, staff considers this RAI to be closed.

In RAI 2.3.2.3-3, the NRC staff requested that the applicant explain the LRA's treatment of heat exchanger tubesheets, so that the staff could verify that the applicant had appropriately applied the screening criteria of 10 CFR 54.21(a)(1). Although the applicant's treatment of the CV spray pump seal heat exchanger prompted RAI 2.3.2.3-3, the NRC staff's review discerned an apparent discrepancy with respect to the treatment of heat exchanger tubesheets throughout the LRA (i.e., in certain sections, heat exchanger tubesheets were listed as a separate entry in the AMR results tables, while in the tables of other sections, they were not explicitly listed). Therefore, the staff framed RAI 2.3.2.3-3 to be applicable to tubesheets throughout the entire LRA. The applicant's response to this RAI states that the CV spray pump seal heat exchanger does not contain a tubesheet but is essentially a cooler with cooling coils inside a closed container.

However, the applicant agreed that heat exchanger tubesheets can provide a pressure boundary that is necessary for heat exchangers to perform their intended function(s) for license renewal, and that inconsistencies exist in the identification of heat exchanger subcomponents in the LRA. Therefore, in response to the staff's RAI, the applicant resubmitted entries for heat exchanger subcomponents associated with LRA Tables 2.3-2, 2.3-3, 2.3-4, 2.3-9, 2.3-10, 3.2-1, 3.2-2, 3.3-1, 3.3-2, 3.4-1, and 3.4-2 to correct the identified inconsistencies. The staff finds the applicant's response to RAI 2.3.2.3-3 to be acceptable because the applicant clarified that the CV spray pump seal heat exchanger does not contain a tubesheet, thereby confirming that LRA Table 2.3-4 did not omit this component from the AMR screening required by 10 CFR 54.21(a)(1). The applicant's revisions to the other LRA tables resubmitted in response to this RAI are evaluated in the corresponding sections of this SER.

2.3.2.3.3 Conclusions

The staff reviewed the LRA, the accompanying scoping boundary drawings, and the applicant's RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of its review, the staff concludes that the applicant has adequately identified the components of the CSS that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the CSS that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.4 Containment Air Recirculation Cooling System

2.3.2.4.1 Summary of Technical Information in the Application

The applicant describes the containment air recirculation cooling system in LRA Section 2.3.2.4 and provides a list of components subject to an AMR in LRA Table 2.3-5.

The intended function performed by the containment air recirculation cooling system, in conjunction with the CSS, is to limit the temperature and pressure within the containment during DBAs to less than the design values for the containment. These two separate, full-capacity systems use diverse engineered features to achieve their intended containment heat removal functions, thereby providing an additional degree of redundancy.

The containment air recirculation cooling system consists of four air handling units, each including a fan, a cooling coil, dampers, and a duct distribution system. The air handling units are spaced around the operating floor adjacent to the containment wall. The service water system provides the cooling water that flows through the finned coils of the containment air recirculation system coolers. The containment air recirculation cooling system cools the containment atmosphere during and following an accident by recirculating air through the coolers to reduce the pressure inside containment to atmospheric pressure.

In LRA Table 2.3-5, the applicant identified seven component types of the containment air recirculation cooling system as being within the scope of license renewal and subject to an AMR:

(1) closure bolting
(2) equipment frames and housings
(3) flexible collars
(4) heating/cooling coils
(5) valves
(6) ductwork and fittings
(7) damper mountings

The LRA further identifies that each of these component types, except for damper mountings, provides a pressure-boundary intended function. The intended function of the damper mountings component type is identified as structural support. In addition to the intended function of pressure boundary, the heating/cooling coils component type is also identified as providing an intended function of heat transfer.

2.3.2.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.4 and UFSAR Section 6.2.2 to determine whether there is reasonable assurance that the components of the containment air recirculation cooling system within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

In the performance of its review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Generally, the staff's review of the LRA found the applicant's scoping and screening results to be in accordance with 10 CFR 54.4 and 10 CFR 54.21. However, the staff's scoping review identified several components that appear to support the performance of the containment air recirculation cooling system's intended function that were not identified as being within the scope of license renewal. Also, the staff's screening review identified several passive, long-lived components of the containment air recirculation cooling system that meet the scoping criteria of 10 CFR 54.4 which did not appear to be included in LRA Table 2.3-5. On February 11, 2003, the NRC staff issued RAIs to the applicant to determine whether the applicant had properly applied to these components the scoping criteria of 10 CFR 54.4 and the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs, and the applicant's responses, dated April 28, 2003, are described below.

In RAI 2.3.2.4-1, the NRC staff requested that the applicant explain its finding that two specific containment air recirculation cooling system fans (i.e., HVH-9A and HVH-9B), their suction flowpath (up to the first isolation damper), and their discharge flowpath are not within the scope of license renewal in accordance with 10 CFR 54.4(a). These fans and their associated components appear to provide cooling to the RV, vessel supports, and/or vessel shielding. The applicant's response to this RAI explains that, although fans HVH-9A and HVH-9B and their associated components cool SCs in support of normal plant operation, the system's intended function of containment cooling is performed exclusively by containment air recirculation cooling system fans HVH-1, -2, -3, and -4. The staff finds the applicant's response to RAI 2.3.2.4-1 to be acceptable because the applicant confirmed that fans HVH-9A and HVH-9B and their associated components do not satisfy the license renewal scoping criteria set forth in

10 CFR 54.4(a). Therefore, staff considers this RAI to be closed.

In RAI 2.3.2.4-2, the NRC staff requested that the applicant identify whether a rectangular component labeled "V.D." (which was unidentifiable to the staff), highlighted as being within the scope of license renewal on a scoping boundary drawing of the containment air recirculation cooling system, is subject to an AMR in accordance with 10 CFR 54.21(a)(1). The applicant's response to this RAI states that the unidentifiable component is a volume damper. The applicant states that volume dampers are constructed of the same material as the duct in which they reside and are considered to be a subcomponent of the duct. The applicant further states that volume dampers are included in the component group entitled "Ductwork and Fittings," which is identified in LRA Table 2.3-5 as being subject to an AMR. The applicant's response to RAI 2.3.2.4-2 provided the information requested by the staff and is consistent with 10 CFR 54.21(a)(1). Therefore, the staff finds the applicant's response to be acceptable and considers this RAI to be closed.

In RAI 2.3.2.4-3, the NRC staff requested that the applicant identify whether the ventilation dampers and downstream ductwork composing the normal suction flowpath for four containment air recirculation cooling system fans (i.e., HVH-1, -2, -3, and -4) are within the scope of license renewal, in accordance with 10 CFR 54.4(a), and subject to an AMR, in accordance with 10 CFR 54.21(a)(1). The scoping boundary drawing associated with this system indicates that the normal suction flowpath for these four fans is not within the scope of license renewal. However, upon reviewing Section 6.2.2.2.2 of the UFSAR, the staff determined that the ventilation dampers and downstream ductwork in these fans' suction flowpaths provide a pressure-boundary intended function that is relied upon to support the containment air recirculation cooling system's intended function. The applicant's response to this RAI agrees that the ductwork and ventilation dampers described above are within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). The response further states that (1) the incorrect scoping boundary drawing will be revised to properly identify the license renewal scoping boundary, (2) the passive, long-lived components brought within scope will be identified as requiring an AMR in accordance with 10 CFR 54.21(a)(1), and (3) applicable aging management program requirements will be in effect. The staff notes that no changes to LRA Table 2.3-5 are required in response to this RAI because entries for component groups encompassing dampers and ductwork previously existed. The staff finds the applicant's response to this RAI to be acceptable because the applicant identified the ventilation dampers and ductwork described above as being within the scope of license renewal, in accordance with 10 CFR 54.4(a)(1), and confirmed that the passive, long-lived components brought within scope will be subject to an AMR in accordance with 10 CFR 54.21(a)(1). Therefore, the staff considers this RAI to be closed.

In RAI 2.3.2.4-4, the NRC staff requested that the applicant identify whether eight semicircular or horseshoe-shaped symbols (which were unidentifiable to the staff) on a scoping boundary drawing of the containment air recirculation cooling system represent components that are within the scope of license renewal in accordance with 10 CFR 54.4(a). Each of the semicircular symbols on the diagram is located just inside the shield wall, at the termination of a discharge line from a containment air recirculation cooling system fan. The staff was unable to discern from the diagram whether the unidentified components had been highlighted by the applicant as being within the scope of license renewal, and, if so, whether they had been included in the AMR results in LRA Table 2.3-5. The applicant's response to this RAI states that the semicircular symbols cited by the staff depict the physical relationship of the duct as it branches off the containment ring header. The response further states that no additional entries are required for LRA Table 2.3-5 because the symbols do not represent a specific component that is within the scope of license renewal in accordance with 10 CFR 54.4(a). As the applicant's response provides the additional information requested by the staff, the staff considers this RAI to be closed.

2.3.2.4.3 Conclusions

The staff reviewed the LRA, the accompanying scoping boundary drawings, and the applicant's RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of its review, the staff concludes that the applicant has adequately identified the components of the containment air recirculation cooling system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the containment air recirculation cooling system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.5 Containment Isolation System

2.3.2.5.1 Summary of Technical Information in the Application

The applicant describes the containment isolation system in LRA Section 2.3.2.5 and provides a list of components subject to an AMR in LRA Table 2.3-6.

The intended function performed by the containment isolation system is to provide for the closure and integrity of containment penetrations to prevent the uncontrolled or unmonitored leakage of radioactive materials to the environment.

The LRA defines the containment isolation system as consisting of eight mechanical process systems listed below whose only intended function is containment isolation.

(1) postaccident hydrogen system
(2) service air system
(3) process/area radiation monitoring
(4) containment pressure relief system
(5) containment vacuum breaker system
(6) liquid waste processing system
(7) penetration pressurization local leak rate test
(8) isolation valve seal water system

Mechanical process systems that have intended functions for license renewal in addition to containment isolation are included in other sections of the LRA. The pressure boundary portions of electrical penetrations and miscellaneous or spare mechanical penetrations that are not associated with a process system are included in Section 2.4 of the LRA, and the electrical portions of containment electrical penetrations are included in LRA Section 2.5.

In LRA Table 2.3-6, the applicant identified two component types of the containment isolation system as being within the scope of license renewal and subject to an AMR—(1) closure bolting and (2) valves, piping, and fittings.

The LRA further identifies that the intended function of the closure bolting component type is to provide a pressure boundary, and that the intended function of the valves, piping, and fittings component type is to provide a pressure boundary and to provide structural support to safety-related components.

2.3.2.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.5 and various sections of the UFSAR, including 6.2.4, 6.2.5, 9.3.1, 9.3.2, 12.3.3, 9.4.3.2.7, and 11.2, to determine whether there is reasonable assurance that the components of the containment isolation system within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

In the performance of its review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

With the exceptions described below, the staff's scoping review found that the LRA generally identifies the components of the containment isolation system which are necessary to effect containment isolation as being within the scope of license renewal. The staff finds this approach to be acceptable for all of the systems included in the containment isolation system except for the postaccident hydrogen system (which is discussed below), because these systems are nonessential except for their containment-isolation intended function. The staff's review of the AMR results in LRA Table 2.3-6 did not identify the omission of any passive, long-lived components that had been considered by the applicant to be within the scope of license renewal. On February 11, 2003, the NRC staff issued RAIs to the applicant to address the scoping concerns identified by the staff regarding the postaccident hydrogen system and other portions of the containment isolation system. The staff's RAIs and the applicant's responses, dated April 28, 2003, are described below.

In RAIs 2.3.2.5-1, 2.3.2.5-2, and 2.3.2.5-3, the NRC staff requested additional information concerning the postaccident hydrogen system. RAI 2.3.2.5-1 requested that the applicant justify not identifying hydrogen control as an intended function for the postaccident hydrogen system. On the basis of descriptions from the UFSAR, including statements from Section 6.2.5.1, the NRC staff determined that the hydrogen recombiners are relied upon in the current safety analysis to prevent the accumulation of a combustible concentration of hydrogen within the containment building. RAI 2.3.2.5-2 requested that the applicant justify excluding from the scope of license renewal the components comprising the pressure boundary of the postaccident hydrogen system (except for those components already in scope for containment isolation), and to justify excluding any passive, long-lived, pressure-boundary components from an AMR. RAI 2.3.2.5-3 requested that the applicant justify excluding from the scope of license renewal the components needed to operate containment isolation valves and other pneumatic valves to support the hydrogen control function described in the UFSAR and to justify excluding any passive, long-lived components from an AMR.

The applicant's response to RAI 2.3.2.5-1 states that hydrogen control is considered to be a mitigative function following a LOCA, but the hydrogen control systems do not perform an intended function for license renewal. The response explains that, although operation of the hydrogen recombiners is the preferred method for hydrogen control, recombiner operation is considered a recovery action because of the long time period (approximately 54 days) before it is required. As a result, the response states that there is sufficient time to assure the operability of all components in the recombiner system before its operation is required. The response further indicates that the hydrogen recombiner and its supporting components are not safety-related. The applicant's responses to RAIs 2.3.2.5-2 and 2.3.2.5-3 reference these arguments from the response to RAI 2.3.2.5-1 to justify the exclusion from the scope of license renewal of the pressure boundary components of the hydrogen recombiner system (other than those necessary for containment isolation) and the components necessary to operate pneumatic valves in support of hydrogen recombiner operation.

The staff considers the applicant's responses to RAIs 2.3.2.5-1, 2.3.2.5-2, and 2.3.2.5-3 to be unacceptable because they are incomplete. Although the responses provide sufficient information to demonstrate that 10 CFR 54.4(a)(1) and (a)(3) do not apply to the hydrogen recombiners and supporting components, they do not adequately demonstrate that these components are not within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). Specifically, although ample time is available to effect hydrogen control, 10 CFR 54.4 does not explicitly permit components required for accident mitigation to be excluded from the scope of license renewal on that basis. In addition, although the response states that sufficient time exists to ensure that all components of the recombiner system are operable before its operation is required, UFSAR Section 6.2.5.2.2 indicates that the majority of the lines associated with this system cannot be repaired due to the high radiation rates present during postaccident conditions.

The staff explained the basis for its determination of unacceptability to the applicant during a public meeting on May 20, 2003. Following this meeting, the applicant reassessed its responses to RAIs 2.3.2.5-1, 2.3.2.5-2, and 2.3.2.5-3, and, by letter from J.F. Lucas dated September 16, 2003, transmitted a revised response to these items that would bring within scope the components of the hydrogen recombiner system that are necessary to fulfill the hydrogen control intended function. Specifically, in addition to the components necessary for containment isolation, the response brings within scope the hydrogen recombiner, permanently installed piping, and temporary flexible piping associated with the postaccident hydrogen system pressure boundary, as well as the passive pressure boundary components of the associated nitrogen system that actuates the containment isolation valves which would permit the flow of containment atmosphere to and from the hydrogen recombiner. Based on the applicant's decision to bring those components within scope of license renewal, the staff finds the applicant's responses to RAIs 2.3.2.5-1, 2.3.2.5-2, and 2.3.2.5-3 acceptable, and Confirmatory Item 2.3.2.5-3 is closed.

In RAIs 2.3.2.5-4 and 2.3.2.5-5, the NRC staff requested additional information concerning the hydrogen analyzers. RAI 2.3.2.5-4 requested that the applicant justify not identifying hydrogen monitoring as an intended function for license renewal. On the basis of descriptions contained in Section 6.2.5 of the UFSAR, the staff determined that the hydrogen analyzers are necessary to support proper operation of the hydrogen recombiners. In RAI 2.3.2.5-5, the staff asked the applicant to explain why the LRA did not identify any passive, long-lived, pressure boundary components associated with the hydrogen analyzers' intended function of hydrogen monitoring.

In response to these RAIs, the applicant indicated that the hydrogen analyzers do perform an intended function (hydrogen monitoring) and are therefore considered to be within the scope of license renewal. The applicant further stated that the LRA classifies the hydrogen analyzers within the postaccident monitoring system, which consists solely of components considered to be electrical/instrumentation and controls (I&C). The applicant stated that the hydrogen analyzers are located within the containment building and that, therefore, there are no pressure boundary components that are required to support their intended function. The applicant's response provides sufficient basis for the staff to have reasonable assurance that no mechanical components associated with the hydrogen analyzers have been omitted from the scope of license renewal. Therefore, the staff finds the applicant's responses to RAIs 2.3.2.5-4 and 2.3.2.5-5 to be acceptable and considers these RAIs to be closed.

In RAI 2.3.2.5-6, the NRC staff requested that, considering 10 CFR 54.4(a), the applicant justify excluding from the scope of license renewal the debris screens and intervening piping between the containment atmosphere and the containment isolation valves for the containment pressure relief and containment vacuum breaker systems. The staff's review identified that Section 9.4.3.2.7 of the UFSAR states that the debris screens ensure that airborne debris will not interfere with the tight closure of the butterfly valves used for containment isolation. As the debris screens and piping appear to be passive and long-lived components, the staff further requested that the applicant consider whether these components should be subject to an AMR, in accordance with 10 CFR 54.21(a)(1). The applicant's response to this RAI affirms that the debris screens for the butterfly valves and the intervening piping perform an intended function for license renewal and will be subject to an AMR. The staff finds the applicant's response to this RAI to be acceptable because the applicant affirmed that the debris screens and intervening piping are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). Therefore, the staff considers RAI 2.3.2.5-6 to be closed.

2.3.2.5.3 Conclusions

The staff reviewed the LRA, the accompanying scoping boundary drawings, and the applicant's RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. On the basis of its review, the staff concludes that the applicant has adequately identified the components of the containment isolation system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the containment isolation system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3 Auxiliary Systems

2.3.3.1 Sampling Systems

2.3.3.1.1 Summary of Technical Information in the Application

The applicant describes the sampling systems in LRA Section 2.3.3.1 and provides a list of components subject to an AMR in LRA Table 2.3-7.

Sampling systems include the primary sampling system, the steam cycle sampling system, the containment vapor and pressure sampling system, and the postaccident sampling system. The applicant indicated that the Class I portions of the primary sampling system are addressed in Subsection 2.3.1.1, and steam cycle sampling is addressed in Subsection 2.3.4.7.

The primary sampling system provides representative samples for laboratory analysis to evaluate the chemistry of the reactor coolant, RHR system, SI system, steam system, and CVCS during normal operation. The system is operated manually on an intermittent basis. The primary sampling system is described in RNP UFSAR Section 9.3.2.1.

The containment vapor and pressure sampling system provides the means to monitor containment pressure. The postaccident sampling system provides a means to remotely collect reactor coolant, containment atmosphere, and other samples following a postulated accident. The postaccident sampling system is divided into two basic system parts—reactor coolant sampling and containment air sampling. Reactor coolant samples are provided from the primary sampling system. Containment air samples are provided via the penetration pressurization system local leak rate test system from the process/area radiation monitoring system. The postaccident sampling system is described in RNP UFSAR Section 9.3.2.2.

2.3.3.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.1 and UFSAR Sections 9.3.2.1 and 9.3.2.2 to determine whether there is reasonable assurance that the sampling system within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

As a result of this review, the staff questioned the applicant (RAI 2.3.3.1-1) as to why the traps T-56A, B, and C shown on the flow diagram HBR2-6490LR are within the scope of components that require an AMR but not included in sampling systems Table 2.3-7 for component/commodity groups requiring AMR. By letter dated April 28, 2003, the applicant responded to this RAI by stating that the traps are included under "Valves, Piping, Tubing and Fittings" in the components/commodity groups requiring an AMR on Table 2.3-7 of the containment vapor and pressure sampling system. The staff finds the applicant's response acceptable because the applicant identified that traps are in scope and subject to AMR.

The staff also questioned the applicant (RAI 2.3.3.1-2) as to why the piping on the primary sampling system flow diagram 5379-353 LR (a) between valves PS-951 and P-29, (b) between valves PS-953 and P-30, (c) between valves PS-955A/B and P-31, (d) between valves PS-975 and PS-977/PS 976, (e) between valves PS-974B and PS-988, and (f) between valves PS-969B and PS-985 is not shown within the scope of components requiring AMR.

By letter dated April 28, 2003, the applicant responded to RAI 2.3.3.1-2 by stating that the primary sampling system is not required for safe shutdown or to mitigate the consequences of an accident and is therefore classified as a non-safety-related system. However, the sample lines that interface with safety-related systems are provided with isolation valves, and those that penetrate the containment are provided with two isolation valves in series outside the containment which close upon actuation of the containment isolation signal. The valves that are closed by the containment isolation signal are PS-956A through PS-956H. The valves that provide isolation to the safety-related systems are PS-951, PS-953, PS-955A through PS-955E, and PS-959. Manual valves PS-976, PS-977, PS-988, and PS989D are the safety-related boundary valves for the CVCS. Components of the primary sampling system downstream of valves PS-956B, PS-956D, PS-956F, PS-956H, PS-959, PS-976, PS-977, PS-988 and PS-898 are not safetyrelated.

The primary sampling system is in scope because it has the following intended functions.

- maintain reactor coolant system pressure boundary
- provide containment isolation
- provide a pressure-retaining boundary to prevent spatial interactions with safety-related equipment

The portion of the system relied on to support the maintenance of the RCS pressure boundary is defined by the Class 1 components within the system. This boundary ends at valves PS-951, PS-953, PS-955A, and PS-955B, as shown on the drawing 5379-353LR. The penetration and the downstream piping, including the double isolation valves outside containment, support the containment isolation function as illustrated by the highlighted portion (included in AMR).

The portion of piping inside the containment from the Class 1 boundary to the containment penetration and the piping within the reactor auxiliary building (RAB) do not require an AMR since they do not have a spatial interaction with safety-related equipment as presented in attachment V of RNP-RA/02-0159, letter from J. Moyer (Carolina Power & Light Company (CPLC) to the NRC, "Supplement to Application for Renewal of Operating License," dated October 23, 2002.

The staff has reviewed the applicant's response to RAI 2.3.3.1-2 and finds it acceptable. The response to RAI items (a), (b), and (c) is acceptable because the applicant identified that the subject piping does not require an AMR since it does not have a spatial interaction with safety-related equipment. The response to RAI items (d) and (e) is acceptable because the applicant identified the subject piping as in scope in the CVCS and subject to AMR. The response to RAI item (f) is acceptable because the applicant identified the subject piping as not safetyrelated and not subject to AMR.

2.3.3.1.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings and the applicant's response (dated April 28, 2003) to the RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the sampling systems that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the sampling systems that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.2 Service Water System

2.3.3.2.1 Summary of Technical Information in the Application

The applicant describes the service water system (SWS) in LRA Section 2.3.3.2 and provides a list of components subject to an AMR in LRA Table 2.3-8.

The SWS is an open loop system and provides makeup water to and removes heat from several plant systems. Redundant supply paths with isolation valves are provided to those systems required for safety either during normal operation or under postulated accident conditions. The system removes heat from the CCW system; heating, ventilation, and air conditioning (HVAC) systems in the containment building, auxiliary building, control room area, fuel handling building, and safety-related pump rooms; emergency diesel generators (EDGs); certain safety-related pumps; and various heat loads in the turbine building. The system provides a backup, long-term water supply to the AFW system. The system contains four vertical wet pit service water pumps and two full-capacity service water booster pumps that supply water to the containment fan coolers. The SWS is described in RNP UFSAR Section 9.2.1.

2.3.3.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.2 and UFSAR Section 9.2.1 to determine whether there is reasonable assurance that the SWS components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

As a result of this review, the staff questioned the applicant as to why the plant coolers and heat exchangers shown on the SWS flow diagram G-190199LR, sheets 4, 5, 6, 9, and 10, as within the scope of service water components that require an AMR because they provide a pressure-retaining function are not included in SWS Table 2.3-8 for component/commodity groups requiring AMR. The applicant was requested (RAI 2.3.3.2-1) to identify where the LRA addresses the AMR of these components, because this information was not indicated in Section 2.3.3.2. By letter dated April 28, 2003, the applicant responded to this RAI by stating that plant coolers and heat exchangers within the scope of license renewal are subject to environments from two separate systems. Accordingly, these heat exchangers and coolers interfacing with the SWS are depicted on the service water flow diagrams as well as the corresponding system flow diagrams. These components are included in the evaluation for their respective system LRA tables for AMR as indicated below:

- containment air recirculating units (HVH-1, 2, 3 and 4)—in LRA Table 2.3-5 (Drawing

G-190304LR, sheet 1)

- safety injection pumps A, B, and C—in LRA Table 2.3-3 (drawing 5379-1082LR, sheet 2)

- air recirculating cooling units (HVH-6A and 6B)—in LRA Table 2.3-18 (drawing G-190304LR, sheet 2)

- diesel generator air coolers or after coolant heat exchangers (A and B)—in LRA Table 2.3-22 (drawing G-190204A LR, sheet 3)—Although these are identified as "air coolers" on the service water boundary drawing, the components interfacing with the service water system are the "after coolant heat exchangers (A and B)" as identified on the diesel generator boundary drawing.

- lube oil coolers (A and B) and jacket water heat exchanger (A and B)—in LRA Table 2.3-22 (drawing G-190204ALR, sheet 3)

- auxiliary feed water pumps and oil coolers (A and B)—in LRA Table 2.3-29 (drawing G-190197LR, sheet 4)

- component cooling water heat exchangers (A and B)—in LRA Table 2.3-9 (drawing 5379-376LR, sheet 1)

- air recirculating units (HVH-7A and 7B)—in LRA Table 2.3-18 (drawing G-190304LR, sheet 2)

- control room refrigeration units (WCCU-1A and 1B)—in LRA Table 2.3-19 (drawing G-190304LR, sheet 4)

- residual heat removal air recirculating units (HVH-8A and 8B)—in LRA Table 2.3-18 (drawing G-109304LR, sheet 2)

- steam-driven auxiliary feedwater pump oil coolers—in LRA Table 2.3-29 (drawing G-190197LR, sheet 4)

The staff also questioned the applicant (RAI 2.3.3.2-2) as to why the penetration coolers, flow indicators, and connecting piping on service water flow diagram G-190199LR, sheet 3, are not shown within the scope of components requiring an AMR. By letter dated April 28, 2003, the applicant responded to this RAI by stating that the penetration coolers and connecting piping (including the flow instrumentation) are not required to support a system intended function as indicated in UFSAR (Revision 15) Section 9.2.1.2, item i, which states that the service water flow to the containment piping penetration coolers is isolated. Therefore, these components are not within the scope.

The staff has reviewed the above information and finds it acceptable because all the safety-related plant coolers and heat exchangers within the scope of license renewal that interface with SWS for pressure-retaining function are included in the list of components requiring AMR.

2.3.3.2.3 Conclusions

The staff reviewed the LRA, the accompanying scoping boundary drawings, and the applicant's responses (dated April 28, 2003) to RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the service water system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the SWS that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.3 Component Cooling Water System

2.3.3.3.1 Summary of Technical Information in the Application

The applicant describes the component cooling water (CCW) system in LRA Section 2.3.3.3 and provides a list of components subject to an AMR in LRA Table 2.3-9.

The CCW system provides a heat sink for the removal of process and operating heat from safety-related components during postulated accidents or transients. During normal operation, the CCW system also provides this function for various nonessential components, as well as the spent fuel storage pool. The CCW system serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the SWS, and thus to the environment. The CCW system consists of three pumps, two heat exchangers, a supply and return header, a surge tank, and associated piping, valves, and instrumentation. The CCW system is described in RNP UFSAR Section 9.2.2.

2.3.3.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.3 and UFSAR Section 9.2.2 to determine whether there is reasonable assurance that the CCW system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.3-9 of the CCW system lists the heat exchangers whose tubes and shell are within the scope of components requiring an AMR because they provide a pressure-retaining function. The staff questioned the applicant (RAI 2.3.3.3-1) as to why the tubesheets of these heat exchangers (except the CCW heat exchangers) are not listed in Table 2.3-9 for component/commodity groups requiring AMR. By letter dated April 28, 2003, the applicant responded to this RAI by stating that the spent fuel pool (SFP) cooling heat exchanger, the nonregenerative heat exchanger, and waste gas compressor coolers have tubesheets that were not identified in the initial submittal. Since the initial submittal, the RNP LR evaluation has been updated to include these corrections. Other sample heat exchangers and control rod drive mechanism (CRDM) cooling coolers listed in Table 2.3-9 do not have tubesheets. These heat exchangers are shell and flanged cooler-type heat exchangers, and the cooling coils (tubing) pass directly through the flanged cover into the shell.

The staff also questioned the applicant (RAI 2.3.3.3-2) as to why the heat exchangers and pump coolers of charging pumps, reactor coolant, RHR, seal water, excess letdown, containment spray pump, and high-head SI pumps are shown on the CCW system flow diagram 5379-376LR (sheets 1, 2, 3, and 4) as within the scope of components that require an AMR but not included in CCW system Table 2.3-9 for component/commodity groups requiring AMR. The applicant was requested to identify where the LRA addresses the AMR of these components because this information was not indicated in Section 2.3.3.3. By letter dated April 28, 2003, the applicant responded to this RAI by stating that the above heat exchangers and pump coolers within the scope of license renewal are subject to environments from two separate systems. Accordingly, the heat exchangers and coolers interfacing with the CCW system are depicted on the CCW system flow diagrams, as well as on the corresponding system flow diagrams. These components are included in the evaluation for their respective system LRA tables for AMR as indicated below:

- The charging pump heat exchangers, seal water heat exchanger, and excess letdown heat exchanger are included in the chemical and volume control system LRA Table 2.3-10.

- The reactor coolant heat exchanger refers specifically to the hot-leg sample heat exchanger which supports only the component cooling water intended function and is listed in the component cooling water system LRA Table 2.3-9.

- Residual heat removal heat exchangers and pump coolers are included in the residual heat removal system LRA Table 2.3-2.

- Reactor coolant pumps are included in the reactor coolant system LRA Table 2.3-1.
- Containment spray pump coolers are included in the containment spray system LRA Table 2.3-4.

- High-head safety injection pump coolers are included in safety injection system LRA Table 2.3-3.

The staff has reviewed the above information and finds it acceptable because all the safety-related pumps, coolers, and heat exchangers within the scope of license renewal that interface with the CCW system for a pressure-retaining function are included in the list of components requiring AMR.

2.3.3.3.3 Conclusions

The staff reviewed the LRA, the accompanying scoping boundary drawings, and the applicant's response (dated April 28, 2003) to RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the CCW system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the CCW system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.4 Chemical and Volume Control System

2.3.3.4.1 Summary of Technical Information in the Application

The applicant describes the CVCS in LRA Section 2.3.3.4 and provides a list of components subject to an AMR in LRA Table 2.3-10.

The applicant's LRA contains the following description of the CVCS.

The CVCS provides a continuous feed and bleed of reactor cooling water for the RCS to maintain proper water level and to adjust boron concentration. The CVCS provides a means for injection of control poison in the form of boric acid solution, chemical additions for corrosion control, and reactor coolant cleanup and degasification. The system also adds makeup water to the RCS, reprocesses water letdown from the RCS and charging pump leakage, and provides seal water injection to the RCP seals.

The CVCS is in the scope of license renewal, because it contains SCs that are safety-related and are relied upon to remain functional during and following design-basis events, SCs that are not safety-related but whose failure could prevent satisfactory accomplishment of the safety-related functions, SCs that are part of the Environmental Qualification Program, and SCs that are relied on during postulated fires and SBO events.

2.3.3.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.4 and UFSAR Section 9.3.4 to determine whether there is reasonable assurance that the CVCS components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

2.3.3.4.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the CVCS that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the CVCS that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.5 Instrument Air System

2.3.3.5.1 Summary of Technical Information in the Application

The applicant describes the instrument air (IA) system in LRA Section 2.3.3.5 and provides a list of components subject to an AMR in LRA Table 2.3-11.

The IA system provides a reliable source of dry, oil-free air for controls and motive power to safety-related and non-safety-related I&C and pneumatic valves. Safety-related, air-operated valves that are required to operate following design-basis events and are normally supplied by IA are provided with backup sources of either air (accumulators) or nitrogen. The system contains air compressors, air dryers, air receivers, and interconnecting piping and valves. The IA system is described in RNP UFSAR Section 9.3.1.

2.3.3.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.5 and UFSAR Section 9.3.1 to determine whether there is reasonable assurance that the IA system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The staff also questioned the applicant (RAI 2.3.3.5-1 and RAI 2.3.3.6-2) as to why the accumulators shown on the instrument and station air system Flow Diagram G-190200LR (sheet 9 as within the scope of components requiring an AMR are not listed in the IA system Table 2.3-11 for component/commodity groups requiring an AMR. By letter dated April 28, 2003, the applicant responded to this RAI by stating that the accumulators shown on the diagram G-1902000LR (sheet 9) are the pressurizer nitrogen supply accumulators A and B and are listed on the nitrogen supply/blanketing system Table 2.3-12 for component/commodity groups requiring an AMR. The staff finds the applicant's response acceptable because the applicant identified these as nitrogen supply accumulators subject to AMR as listed on the nitrogen/blanketing system Table 2.3-12.

2.3.3.5.3 Conclusions

The staff reviewed the LRA, the accompanying scoping boundary drawings, and the applicant's response (dated April 28, 2003) to RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the IA system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the IA system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.6 Nitrogen Supply/Blanketing System

2.3.3.6.1 Summary of Technical Information in the Application

The applicant describes the nitrogen supply/blanketing system in LRA Section 2.3.3.6 and provides a list of components subject to an AMR in LRA Table 2.3-12.

The nitrogen supply/blanketing system provides gas for various plant functions as the motive force for some gas-operated valves, to pressurize the SI system accumulators, and to provide inert cover gas for certain tanks. Portions of the system provide motive force for the pressurizer PORVs. The nitrogen supply/blanketing system is described in UFSAR Sections 6.2.5.2.2, 6.8.2.1, 6.9.2.1, and 7.6.1.

2.3.3.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.6 and UFSAR Sections 6.2.5.2.2, 6.8.2.1, 6.9.2.1, and 7.6.1 to determine whether there is reasonable assurance that the nitrogen supply/blanketing system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Steam dump nitrogen accumulator and connecting piping is shown on the nitrogen supply system Flow Diagram HBR2-8606LR (sheet 2) as within the scope of components requiring an AMR. The staff questioned the applicant (RAI 2.3.3.6-1) as to why connecting branch piping is not considered within the scope of license renewal for components requiring an AMR. By letter dated April 28, 2003, the applicant responded to this RAI by stating that the steam dump nitrogen accumulator is credited with pneumatic supply for the SG PORVs in the event of an Appendix R fire. While the accumulator itself and the piping along the flow path from the accumulator to the PORVs are in scope for license renewal, branch piping connections are not postulated to fail during an Appendix R fire and are outside intended function boundaries. The staff finds the applicant's response acceptable because the applicant explained that the subject branch piping is not postulated to fail during an Appendix R fire and is not in scope for AMR.

2.3.3.6.3 Conclusions

The staff reviewed the LRA, the accompanying scoping boundary drawings, and the applicant's response (dated April 28, 2003) to RAIs to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the nitrogen supply/blanketing system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the nitrogen supply/blanketing system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.7 Radioactive Equipment Drain

2.3.3.7.1 Summary of Technical Information in the Application

The applicant describes the radioactive equipment drain system (REDS) in LRA Section 2.3.3.7 and provides a list of components subject to an AMR in LRA Table 2.3-13.

The radioactive equipment drains route potentially radioactive floor drainage to the liquid waste processing system. Portions of the system are relied on during postulated internal fire protection system actuations or failures to drain fire protection water from rooms containing safety-related equipment. The evaluation boundaries for the portions of the radioactive equipment drains that are within the scope of license renewal were determined on the basis of their function following actuation of fire suppression systems in the RAB, as described in UFSAR Appendix 9.5.1B. No flow diagrams were used to determine the evaluation boundaries.

2.3.3.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.7 and UFSAR Section 11.2 and Appendix 9.5.1B to determine whether there is reasonable assurance that the radioactive equipment drain components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Appendix 9.5.1B to the RNP UFSAR states that, based on evaluation of two pipe break locations that typify the areas with water-filled pipe in the auxiliary building, the floor drain system will prevent flooding of electrical safety-related equipment on the second floor. However, 10 CFR 54.21 requires that components subject to an AMR be listed in the application or included by reference. The LRA did not specifically identify the components within the radioactive equipment drains system subject to an AMR other than by listing "piping and fittings" in Table 2.3-13 of the LRA. Therefore, by letter dated February 11, 2003, the staff requested that the applicant clarify which specific piping sections and fittings are within the scope of license renewal and subject to an AMR and how these sections were found to provide protection against flooding from pipe breaks within the auxiliary building.

By letter dated April 28, 2003, the applicant responded to this RAI. The applicant stated that the REDS comprises piping and fittings embedded in the auxiliary building, as well as any connected exposed piping, and these piping sections and fittings are considered to be within the scope of license renewal and subject to an AMR. The applicant further stated that a description of flooding effects from pipe breaks within the auxiliary building is provided by a letter from E. Utley (CP&L) to NRC, Serial NO-80-896 "Fire Protection Program," dated June 12, 1980, and accepted by the NRC in the SER Supplement dated December 8, 1980. The attachment to this letter discussing Item 3.2.7, "Fire Water Pipe Rupture," identified the piping and fittings as (1) seven 3-inch floor drains in the second-level hallway floor at elevation 246 connected to five 3-inch downcomers, (2) one floor drain served by one downcomer in the 230 kV protective relay area, (3) 16 floor drains in the first-level floor at elevation 226, (4) the first-level drain distribution piping, (5) the 375-gallon drain collection sump tank, and (6) independent DG room floor drains that discharge into the storm drain system. The staff found that this reference adequately identified the piping and fittings within the scope of license renewal and subject to an AMR.

During review of LRA Table 2.4-2, which lists component commodity groups subject to an AMR, the staff noted that the table did not specifically describe embedded piping with a pressure boundary intended function to maintain free flow of water through the equipment drain system. By letter dated February 11, 2003, the staff requested that the applicant clarify which portions of the embedded piping are included within the scope of license renewal and are subject to an AMR, the intended function of this embedded piping, and which AMPs apply to the embedded piping.

By letter dated April 28, 2003, the applicant responded to this RAI. The applicant stated that the intended function of the REDS is to drain rooms in the auxiliary building following a postulated fire header rupture to equalize flooding elevations and protect electrical equipment from flooding. Maintaining clear drains and piping accomplishes this function. Therefore, the intended function of the embedded piping is to provide a pressure-retaining boundary so that sufficient flow at adequate pressure is delivered. The applicant stated that the embedded piping external surface was subject to an AMR via the AMR of civil/structural components and commodities since the piping was in a stainless steel material/embedded concrete environment. This review identified no aging effects for the subject stainless steel piping and fittings, and therefore no AMPs were applied. The embedded piping internal surface was subject to the same AMR as exposed piping, which is identified in LRA Table 2.3-13. The staff found that this response adequately addressed the issue of piping embedded in concrete as a commodity subject to an AMR in LRA Table 3.3-2.

2.3.3.7.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the REDS that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the REDS that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.8 Primary and Demineralized Water System

2.3.3.8.1 Summary of Technical Information in the Application

The applicant describes the primary and demineralized water system in LRA Section 2.3.3.8 and provides a list of components subject to an AMR in LRA Table 2.3-14.

The primary and demineralized water system supplies demineralized and deaerated water for process support functions and makeup supplies to various systems throughout the plant. UFSAR Section 9.2.3 provides a description of the primary and demineralized water system.

The license renewal evaluation boundaries for the primary and demineralized water system are shown on flow diagram G-190202LR, sheet 3, which was referenced by the LRA.

2.3.3.8.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.8 and UFSAR Sections 2.4, 9.2.2, 9.2.3, and 10.4.8 to determine whether there is reasonable assurance that the primary and demineralized water system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The staff identified an issue regarding the need for makeup water to the CCW surge tank to prevent failure of the system as a result of leakage. Section 9.2.2.3.1 of the UFSAR states that a leaking heat exchanger could be left in service with leakage up to the capacity of the makeup line to the system, and that water stored in the CCW surge tank together with makeup flow provides adequate time to isolate a leaking cooling line serving an individual RCP cooler before cooling is lost to essential components in the component cooling loop. Section 9.2.3 of the UFSAR describes that the non-safety-related primary makeup water tank provides normal makeup to the CCW system. However, the primary and demineralized water system LR Flow diagram G-190202LR, sheet 3, and CCW system LR flow diagram, 5379-376, sheet 1, indicate that only the safety-related section of piping from valves CC-832 and CC-711 to the component cooling surge tank header is within LR scope. By letter dated February 11, 2003, the staff requested that the applicant clarify whether the non-safety-related piping and components necessary to provide primary makeup water system flow to the component cooling surge tank are included within the scope of license renewal and subject to an AMR or justify their exclusion.

By letter dated April 28, 2003, the applicant responded to this RAI. The applicant stated that the information provided in the UFSAR is intended to show how the system would be operated to mitigate a leak and that the CCW surge tank maintains a volume of water that provides time for the plant operating staff to find and isolate a leak. The applicant also stated that leakage from the CCW system is an anticipated condition, and procedures are in place to mitigate a range of CCW system degradation up to the complete loss of the system. Lastly, the applicant stated that severance of a CCW line as a result of a pipe break in containment is not a postulated event, and evaluations of the CCW lines inside containment had been performed that demonstrated the CCW lines inside containment were protected from the effects of postulated ruptures of high-energy piping. Based on the above information, the applicant concluded that the ability to provide makeup water to the CCW surge tank from the primary and demineralized water system is not required for design-basis events and, therefore, is not an intended function for license renewal as defined in 10 CFR 54.4(b).

The staff reviewed the applicant's response and searched the UFSAR for information supporting the applicant's response. The staff found two relevant statements in Section 9.2.2 of the UFSAR. First, the surge tank ensures a continuous CCW supply until a leaking cooling line can be isolated. Second, based on leak-before-break (LBB) criteria for the primary system, all the component cooling equipment is protected against credible missiles. These statements combined with the applicant's response provide adequate assurance that makeup water from the primary and demineralized water system is not required to maintain the operability of the CCW system following a high-energy line break (HELB) inside containment, based on the CLB of the facility. Therefore, the staff found that the makeup piping to the CCW surge tank does not have an intended function as defined in 10 CFR 54.4, and its exclusion from the scope of license renewal is acceptable.

The staff identified that Section 10.4.8 of the RNP UFSAR includes the following statement:

> In the event of a failure of Lake Robinson Dam, shutdown would be accomplished in an orderly manner using the condensate storage tank. When the condensate storage tank reaches a low level limit, auxiliary feedwater pump suction would be changed to the deepwell pump discharge. This source would provide the required feedwater indefinitely or until such time that some other source of feedwater can be established. It is assumed that emergency power is not required for this accident.

Section 9.2.3 of the UFSAR describes three parallel deepwell pumps as part of the primary and demineralized water system. However, the associated Flow Diagram, G-190202LR, sheet 3, indicates that only the safety-related section of piping from the AFW pump suction to and including valve DW-21 is within LR scope. The remaining piping and components from and including the deepwell pumps to valve DW-21 were not identified as within LR scope. By letter dated February 11, 2003, the staff requested that the applicant clarify whether the non-safety-related piping, valve bodies, and pump casings necessary to provide a pressure-retaining boundary from the deepwell pumps to valve DW-21 are included within the scope of license renewal and subject to an AMR or justify their exclusion.

By letter dated April 28, 2003, the applicant responded to RAI 2.3.3.8-1. The applicant stated that the failure of the dam is not a design-basis event. The Lake Robinson Dam is a non-safety-related structure that has been evaluated to assure its capability to function during and following a design-basis earthquake (DBE). The safety-related SWS provides cooling water for safe plant shutdown, including the long-term backup supply of water to the AFW system from Lake Robinson. The function of supplying safety-related SWS flow is supported by the Lake Robinson Dam, which is in scope for license renewal and monitored by an AMP as discussed in LRA Subsections 2.4.2.10 and B.3.16. The applicant stated that, by including the Lake Robinson Dam in scope for license renewal, the safety functions of the SWS and Lake Robinson are assured during the period of extended operation.

The staff reviewed the applicant's response to RAI 2.3.3.8-1. The context of Section 10.4.8 of the UFSAR does not link dam failure to any particular set of initiating events, and seismic events and age-related degradation do not encompass all credible causes of dam failure. Dam failure results in loss of the ultimate heat sink and loss of the normal backup supply of feedwater from the SWS through the AFW system. Following dam failure and depletion of the condensate storage tank (CST) inventory, failure of the deepwell pumps would cause failure of the safety-related AFW system and prevent the residual heat removal necessary to maintain a safe shutdown condition. Therefore, the deepwell pumps and associated piping are within the scope of LR in accordance with 10 CFR 54.4 (a)(2). The staff found that the applicant has not adequately justified excluding the deepwell pumps and associated piping and valves from an AMR. This was Open Item 2.3.3.8-1.

By letter dated September 16, 2003, the applicant agreed to include, within the scope of license renewal, the three deepwell pumps and associated piping required to provide a backup source of water for the auxiliary feedwater system. The deepwell pumps are vertical turbine-type pumps with integral carbon steel suction piping connected to the pump suction case. This suction piping is integral to the pump and therefore is not shown on the flow diagram. The suction piping is in the well and extends below the pump case. The revised boundary includes the suction piping, deepwell pumps, and piping up to and including the first isolation valve in each branch line. The flow path will connect with valve DW-21 which was included in the original scope of license renewal (refer to boundary drawing G-190202LR, sheet 3, H-3). The staff found that the applicant adequately identified components of the deepwell pumps and associated piping within the scope of license renewal, as required by 10 CFR 54.4(a)(2).

The applicant completed an AMR of the deepwell pumps and associated piping, which resulted in the identification of material/environment combinations not previously identified in the LRA for the primary and demineralized water makeup system. The deepwell pumps are carbon steel/cast iron and are exposed to a raw water environment. The deepwell pump stations are fabricated with carbon steel, stainless steel, and copper alloy valves, piping, and fittings exposed internally to raw water and externally to outdoor air. The piping connected to the pump stations is plastic-coated carbon steel which is run underground. This underground carbon steel piping makes up the majority of the piping in the deepwell system. The suction piping and remaining aboveground piping is carbon steel. The applicant presented the results of the revised aging management evaluations in an update to LRA Table 2.3-14. The staff reviewed the components that were subject to an AMR and found that the applicant has adequately included components of the deepwell pumps and associated piping, as required by 10 CFR 54.21(a)(1). Therefore, Open Item 2.3.3.8-1 is closed. The staff evaluation of the revised AMR results is included in Section 3.3 of this safety evaluation.

2.3.3.8.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the primary and demineralized water system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the primary and demineralized water system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.9 Spent Fuel Pool Cooling System

2.3.3.9.1 Summary of Technical Information in the Application

The applicant describes the spent fuel pool cooling system in LRA Section 2.3.3.9 and provides a list of components subject to an AMR in LRA Table 2.3-15.

The spent fuel pool cooling system (SFPCS) removes decay heat generated by stored spent fuel elements from the spent fuel pool and provides filtering and demineralization of the water in the spent fuel pool. The SFPCS consists of three separate loops—cooling, purification, and skimmer loops. The cooling loop removes heat from the spent fuel pool by circulating water through the spent fuel pool heat exchanger. Heat is removed from this heat exchanger by the component cooling water system. The purification loop provides filtering and demineralization by circulating a portion of the cooling loop flow through a filter and demineralizer. The skimmer loop removes floating debris and surface contaminants that could affect water clarity by taking a suction on the skimmer and circulating the water through a strainer and filter. The applicant stated that functions involving heat removal, purification, and contaminant removal for the spent fuel pool are not intended functions for license renewal. Functions of the SFPCS within scope of license renewal involve maintaining a barrier to support the pressure boundaries of the spent fuel pool (SFP) and the refueling water storage tank (RWST).

2.3.3.9.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.9 and UFSAR Sections 9.1.2, 9.1.3, and 15.7.6 to determine whether there is reasonable assurance that the spent fuel pool cooling system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Section 9.1.3.3.2 of the RNP 2 UFSAR states that the makeup water requirement due to boiling following a complete loss of cooling after a full core offload would be less than 42 gpm. The SFPCS has redundant pumps and procedurally established alternate means of providing heat sink water to the heat exchangers, which ensure that SFP cooling capability can be restored quickly. The SFP large level makeup water source is the RWST via the refueling water purification pump. This path has a capacity of 100 gpm which is more than adequate to replace the water lost. The license renewal boundary diagram for the spent fuel pool cooling system, drawing 5379-1485LR, sheet 1, indicates that the piping and components necessary to deliver makeup water from the RWST to the spent fuel pool are outside of the scope of license renewal, and Section 2.3.3.9 of the LRA states that the heat removal function is not an intended function for license renewal. However, the LRA does not include justification for this determination. By letter dated February 11, 2003, the staff requested in RAI 2.3.3.9-1 that the applicant clarify whether the piping and components necessary for forced cooling of the spent fuel pool and to provide makeup water system flow from the RWST to the spent fuel pool are within the identified scope of license renewal and are subject to an AMR, or justify their exclusion.

By letter dated April 28, 2003, the applicant responded to this request for additional information. The applicant stated that the information provided in the UFSAR discusses evaporation makeup requirements without identifying any potential offsite exposures. Section 15.7.6 of the UFSAR states that the evaporative losses are replenished by primary demineralized water from the 150,000 gallon primary water storage tank. A redundant supply of makeup water is provided by the fire hoses in the vicinity of the spent fuel pit. Although the SFPCS has the capability to be fed by the RWST, the applicant stated that the RWST provides no safety-related function relative to the SFP, and the connected SPFCS piping past the valve isolating the RWST from the SFPCS is nonsafety related. Neither the fire protection equipment, nor the primary water sources in the vicinity of the SFP, are classified as safety related. A loss of an external source of decay heat removal for the spent fuel pool would not cause a significant public dose unless the SFP water level decreased below the level of the stored fuel and subsequent fuel cladding failure occurred. The applicant stated that this would take a minimum of 3 days, over which time, a number of sources of makeup water could be used to compensate for the inventory loss. Among these sources of water are the RWST, the primary water storage tank (PWST), and the fire water system. Based on the above, the applicant concluded that system functions to provide a source of an external cooling for SFPCS and to provide makeup to the SPF for water inventory control are not safety-related functions per the License Renewal Rule (i.e., 10 CFR 54.4(a)(1)(iii)).

The staff reviewed the response and relevant licensing basis information. The last licensing action involving a change in the SFPCS design basis was issued as Amendment 69 to Facility Operating License No. DPR-23 on June 8, 1982. The associated license amendment request was forwarded by letter dated December 1, 1980, and stated that the normal spent fuel pool makeup water source, the RWST, has a capacity of 100 gpm, which is more than adequate to replace the water lost following a loss of forced cooling. The associated NRC safety evaluation noted the makeup capability from the RWST and stated that, in the event of SFPCS pump failure, sufficient pump redundancy or makeup would be available to prevent excessive loss of water from the SFP. Maintenance of an adequate SFP cooling water inventory is necessary to prevent an offsite release comparable to that described in 10 CFR Part 100. Therefore, since failure of the non-safety-related makeup supply from the RWST could cause failure of the safety-related spent fuel cooling provided by an adequate coolant inventory, the piping and components necessary to supply makeup water from the RWST are within the scope of LR in accordance with 10 CFR 54.4 (a)(2).

In further discussions, the applicant agreed to include the SFP makeup path from the RWST to the SFP within the scope of license renewal and add it to the highlighted evaluation boundary drawing. The path from the RWST to the refueling water purification pump suction isolation valve (SFPC-805A, coordinates B-5, 5379-1485LR) was previously included in the evaluation boundary of the safety injection system LR boundary drawing 5379-1082LR, sheet 2. From the refueling water purification pump suction isolation valve, the makeup water flow path returns to the SFP via the purification system demineralizer and filter, the purification loop flow element, the purification loop outlet valve (SFPC-798B), and the SFP cooling system heat exchanger discharge piping. The bypass piping around both the SPF cooling demineralizer and filter are included in the evaluation boundary.

As a result of the expansion of the evaluation boundary, the applicant indicated that LRA Table 2.3-15 would be expanded to include the purification system demineralizer, filter, and pump casing. Each of these components has an intended function of providing a pressure-retaining boundary so that sufficient flow at adequate pressure is delivered. The applicant indicated that the AMR results for these three additional items should refer to Table 3.3-2, Item 1. The remainder of the piping components in the expanded evaluation boundary is represented by the existing items listed in Table 2.3-15.

The staff reviewed the described SFP makeup water flowpath and the additional components identified as subject to an AMR. The staff found that the described list of components identified as subject to an AMR was complete and included the components with an intended function of providing makeup water from the RWST to the SFP. Therefore, written confirmation of these components in the makeup water flow path that are within the scope of license renewal and subject to an AMR is acceptable to satisfy the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a). This action is Confirmatory Item 2.3.3.9-1.

By letter dated August 14, 2003, the applicant formally agreed to include the SFP makeup path from the RWST to the SFP within the scope of license renewal, and described the specific boundaries of the components within the scope of license renewal. As a result of the expansion of the evaluation boundary, the applicant revised LRA Table 2.3-15 to include the SFP cooling demineralizer, SFP filter, and RWP pump. The remainder of the piping components fell within existing commodity groups in LRA Table 2.3-15. The staff found that the formal description of the components subject to an AMR was consistent with the previous communication. Therefore, Confirmatory Item 2.3.3.9-1 has been resolved.

2.3.3.9.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any structures, systems, or components that should be within the scope of license renewal were not identified by the applicant. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the spent fuel pool cooling system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the spent fuel pool cooling system that are subject to an aging management review, as required by 10 CFR 54.21(a)(1).

2.3.3.10 Containment Purge System

2.3.3.10.1 Summary of Technical Information in the Application

The applicant describes the containment purge system in LRA Section 2.3.3.10 and provides a list of components subject to an AMR in LRA Table 2.3-16.

In response to RAI 2.3.3.10-1, the applicant stated that the containment purge system performs the intended functions listed below.

- provides containment isolation
- performs a function to demonstrate compliance with regulations for environmental qualification
- mitigates a fuel handling accident inside containment
- provides instrumentation to monitor variables defined as Category 1 in Regulatory Guide 1.97

The containment purge system consists of an outdoor air intake, supply and exhaust ducts that penetrate the containment, redundant isolation valves, and an exhaust filter bank. The containment purge system is designed to replenish the containment air at a rate to ensure that an effective purge can be accomplished within 2 hours.

In LRA Table 2.3-16, the applicant identified the five component types of the containment purge system listed below as being within the scope of license renewal and subject to an AMR.

(1) closure bolting
(2) ductwork and fittings
(3) equipment frames and housings
(4) flexible collars
(5) valves

The LRA further states that each of these five component types provides a pressure-boundary intended function. In addition, the ductwork and fittings component type is identified as providing structural support.

2.3.3.10.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.10 and UFSAR Section 9.4.3.2.6 to determine whether there is reasonable assurance that the components of the containment purge system within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1).

In the performance of its review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Generally, the staff's review found the scoping and screening results in the LRA to be in accordance with 10 CFR 54.4 and 10 CFR 54.21. However, the staff's review of the applicant's scoping results identified several components that appear to support the performance of the containment purge system's intended functions that were not identified as being within the scope of license renewal. Also, on the basis of its review of the LRA and the UFSAR, the staff could not conclusively identify the intended functions of the containment purge system. On February 11, 2003, the NRC staff issued RAIs to the applicant to address these issues. The staff's RAIs and the applicant's responses, dated April 28, 2003, are described below.

In RAI 2.3.3.10-1, the NRC staff requested that the applicant identify the intended functions of the containment purge system. As the LRA did not include the containment purge system within the containment isolation system (which Section 2.3.2.5 of the LRA identifies as containing the mechanical process systems whose only intended function is containment isolation), the staff questioned whether the intended functions, as defined by 10 CFR 54.4(b), in addition to its apparent containment isolation intended function. The applicant's response to RAI 2.3.3.10-1 identified the intended functions listed in Section 2.3.3.10.1 of this SER. As the applicant provided the information requested by the staff to allow verification that the scoping boundaries defined in the LRA are in compliance with the requirements set forth in 10 CFR 54.4, the staff finds the applicant's response to this RAI to be acceptable. Therefore, the staff considers RAI 2.3.3.10-1 to be closed.

In RAI 2.3.3.10-2, the NRC staff requested that, considering 10 CFR 54.4(a), the applicant justify excluding from the scope of license renewal the debris screens and intervening piping between the containment atmosphere and the containment isolation valves for the containment purge system. The staff's review found that Section 9.4.3.2.6 of the UFSAR states that the debris screens ensure that airborne debris will not interfere with the tight closure of the butterfly valves used for containment isolation. As the debris screens and piping appear to be passive and long-lived components, the staff further requested that the applicant consider whether these components should be subject to an AMR, in accordance with 10 CFR 54.21(a)(1). The applicant's response to this RAI affirms that the debris screens for the butterfly valves and the intervening piping perform an intended function for license renewal and will be subject to an AMR. The staff finds the applicant's response to this RAI to be acceptable because the applicant affirmed that the debris screens and intervening piping are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). Therefore, the staff considers RAI 2.3.3.10-2 to be closed.

2.3.3.10.3 Conclusions

The staff reviewed the LRA, the accompanying scoping boundary drawings, and the applicant's RAI responses to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of its review, the staff concludes that the applicant has adequately identified the components of the containment purge system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the containment purge system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.11 Rod Drive Cooling System

2.3.3.11.1 Summary of Technical Information in the Application

The applicant described the rod drive cooling system in LRA Section 2.3.3.11 and provided a list of components subject to an AMR in LRA Table 2.3-17.

The rod drive cooling system is part of the reactor containment building ventilation system. The primary purpose of the reactor containment ventilation system is to reduce personnel exposure to airborne radioactive contaminants and to prevent excessive equipment operating temperatures. The design basis for the rod drive cooling system is to remove heat generated by the CRDMs. The CRDMs require cooling to keep the coils from gradually degrading.

The rod drive cooling system functions by using air from the containment atmosphere that is drawn downward through a cooling shroud surrounding the CRDMs to absorb the heat that is generated by the rod mechanisms. The system consists of ductwork, a water-cooled heat exchanger, and two 100-percent capacity exhaust fans. The air is drawn from the lower portion of the cooling shroud, cooled by the heat exchanger, and then discharged by the operating fan to the containment atmosphere.

In Section 2.3.3.11 of the LRA, the applicant identified portions of the rod drive cooling system and its SCs that are within the scope of license renewal and subject to an AMR. The applicant stated in the LRA that the rod drive cooling system is further described in Section 9.4.3 of the UFSAR. The applicant identified the following intended functions of the RNP rod drive cooling system based on 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3).

- structures and components that are safety-related and are relied upon to remain functional during and following design-basis events (LRA Section 2.3.3.11)

- structures and components that are relied on during postulated fires (LRA Section 2.3.3.11)

- provide cooling to the control rod drive mechanisms in order to keep coils in the drive mechanisms from gradually degrading (UFSAR Section 9.4.3.4)

On the basis of the intended functions as identified above for the rod drive cooling system, the portions of these systems that were identified by the applicant as within the scope of the LRA include all of the rod drive cooling system safety-related components (electrical, mechanical, and instruments). The applicant described its methodology for identifying the mechanical components subject to an AMR in Section 2.1.2.1 of the LRA. On the basis of this scoping methodology, the applicant identified the portions of the rod drive cooling system that are within scope on the flow diagram listed in Section 2.3.3.11 of the LRA. Using the methodology described in Section 2.1.1 of the LRA, the applicant compiled a list of the mechanical components and component types subject to an AMR that are within the evaluation boundaries highlighted on the flow diagram and identified their intended functions. The applicant provided this list in Table 2.3-17 of the LRA.

Closure bolting, ductwork, fittings, equipment frames, equipment housings, and flexible collars are identified as within the scope of license renewal and subject to an AMR and are listed in Table 2.3-17 of the LRA. The applicant further noted in Table 2.3-17 of the LRA that the rod drive cooling system's intended function is to provide a pressure-retaining boundary so that sufficient flow at adequate pressure is delivered. This pressure boundary function is the only applicable intended function of the rod drive cooling system components that is subject to an AMR.

The applicant evaluated component supports for HVAC ductwork cited in Table 3.5-1 of the LRA. The applicant evaluated electrical components that support the operation of the rod drive cooling system in Section 2.1.2.3 of the LRA. The staff's scoping and screening results for structures are provided in Section 2.4 of this SER. Electrical/I&C scoping and screening results for the rod drive cooling system are provided in Section 2.5 of this SER.

2.3.3.11.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.11 and UFSAR Section 9.4.3 to determine whether there is reasonable assurance that the rod drive cooling system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that are required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

To verify that the applicant identified the components of the rod drive cooling system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and

10 CFR 54.21(a)(1), the staff reviewed the flow diagram listed in Section 2.3.3.11 of the LRA that shows the evaluation boundaries for the highlighted portions of the rod drive cooling system that are within scope and in Table 2.3-17 of the LRA, which lists the mechanical components and the applicable intended functions that are subject to an AMR. The staff also reviewed Section 9.4.3 of the UFSAR to determine if there were any portions of the rod drive cooling system that met the scoping criteria in 10 CFR 54.4(a) but were not identified as within scope. The staff reviewed the UFSAR to determine if there were any safety-related system functions that were not identified as an intended function in the LRA and to determine if there were any structures or components that have an intended function that might have been omitted from the scope of structures or components that require an AMR. The staff compared the functions described in the UFSAR to those identified in the LRA.

Using the scoping and screening methodology described in Section 2.1 of the LRA, the applicant identified the SCs subject to an AMR for the rod drive cooling system and listed them in Table 2.3-17 of the LRA. The staff's evaluation of the scoping and screening methodology is in Section 2.1 of this SER. The staff sampled components subject to an AMR. The staff also sampled SCs that are within the scope of the LRA but are not subject to an AMR. Based on this sample, the staff verified that these SCs perform their intended functions without moving parts or without a change in configuration or properties and are not subject to replacement on the basis of a qualified life or specified time period.

To ensure that those portions of the rod drive cooling system excluded from the scope of license renewal do not perform any intended functions, the staff requested additional information based on a review of the UFSAR and the LRA. The staff noted that Section 2.3.3.11 of the LRA presents a summary description of the system functions and identified a corresponding system flow diagram. The flow diagram highlights the evaluation boundaries, and Table 2.3-17 of the LRA tabulates the components within the scope of license renewal and subject to an AMR for the rod drive cooling system. The corresponding drawings and UFSAR, however, show additional components that were not listed in Table 2.3-17 of the LRA.

The staff noted that the applicant did not identify damper housings, ventilation system passive components, or structural sealants that require an AMR. The scoping and screening determination should consider whether failure of the damper housings, passive components, or structural sealants would result in a failure of the associated active components to perform their intended functions and whether the damper housings, passive components, or structural sealants meet the long-lived and passive criteria as defined in the rule.

In an RAI, the NRC staff noted that ventilation damper housings are not highlighted on ventilation flow diagrams or identified in the LRA as within the scope of license renewal. While ventilation components such as fan housings and cooling coils are highlighted as within the scope of license renewal, ventilation damper housings are not highlighted on the ventilation flow diagrams referenced in the application.

By letter dated April 28, 2003, the applicant provided information stating that ventilation dampers are within the scope of license renewal. The system commodity "Damper Housings" is used to identify damper housings within the scope of license renewal that provide a structural support function. The system commodity "Ductwork" is used to identify damper equipment housings within the scope of license renewal that provide a pressure boundary function. The staff finds this acceptable.

In its April 28, 2003, letter, the applicant stated that system commodity "Ductwork" is also used to identify miscellaneous ductwork components that provide a pressure-retaining function. The licensee stated that ductwork includes ducts, fittings, access doors, equipment housings, flexible collars or connections, and seals.

Access doors, flexible connections, and seals are subject to AMR using the system commodity "Ductwork" grouping for untagged components in HVAC systems. Ductwork test connections are categorized as fittings. Therefore, ductwork test connections are included in the AMR result for the system commodity "Ductwork."

The licensee also stated that turning vanes are within the scope of license renewal and are subject to an AMR. Turning vanes are constructed of the same material as the duct in which they reside and are considered to be a subcomponent of the duct. Therefore, turning vanes are included in the AMR results for ductwork. The staff finds this acceptable.

Some components that are common to many systems, including the rod drive cooling system, have been evaluated separately by the applicant in Section 2.1.2 of the LRA as consumables. The staff notes that the applicant should reference the latest consumable guidance provided in the License Renewal Standard Review Plan, dated April 2001 (NUREG-1800, Table 2.1-3).

In response to RAI 2.1.2-1, by letter dated April 28, 2003, the licensee stated that the evaluation process used to evaluate consumables is consistent with the guidance provided in NUREG-1800, Table 2.1-3. The staff finds this acceptable.

The staff evaluated component supports for piping, cables, and equipment, which are discussed in Section 2.4 of the LRA titled, "Scoping and Screening Results—Structures." In Section 2.5 of this report, the staff evaluated electrical and instrumentation components that support the operation of the rod drive cooling system, which are discussed in Section 2.5 of the LRA titled, "Scoping and Screening Results—Electrical and Instrumentation and Controls (I&C) Systems."

The staff reviewed the LRA, supporting information in the UFSAR, and the applicant's response to RAIs. In addition, the staff sampled several components from the rod drive cooling system flow diagram, as identified in Section 2.3.3.11 of the LRA, to determine whether the applicant properly identified components within the scope of license renewal and subject to an AMR.

2.3.3.11.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the components of the rod drive cooling systems that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the components of the rod drive cooling systems that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.12 Heating Ventilation and Air Conditioning—Auxiliary Building

2.3.3.12.1 Summary of Technical Information in the Application

The applicant described the HVAC for the auxiliary building in LRA Section 2.3.3.12 and provided a list of components subject to an AMR in LRA Table 2.3-18.

The primary purpose of the auxiliary building HVAC system is to provide heat removal to ensure proper operation of safety-related equipment in the auxiliary building. The system provides clean air to the operating areas of the auxiliary building and filters and exhausts air from the equipment rooms and open areas of the auxiliary building. The auxiliary building HVAC system includes a separate ventilation system for the waste evaporator enclosure on the roof of the building. A separate ventilation supply and exhaust system is provided for each DG room and operates when the DG is operating. Also, the system provides for local cooling of safety-related pump rooms.

An exhaust system consisting of two 100-percent capacity exhaust fans, high-efficiency particulate filters, activated carbon adsorbers, and motor-operated dampers is provided to exhaust air from potentially contaminated areas. During normal plant operation, this system is not operating. On a high-radiation signal, the unit is manually started, thus closing the bypass damper and opening the filter damper. The discharge of this system is connected to the intake of the main exhaust units.

Separate redundant room chillers are located in all rooms containing engineered safeguard features pump motors. These rooms contain the low-head RHR pumps, high-head SI pumps, containment spray pumps, and AFW pumps. When starting any pump in these areas, the room chiller unit in that area will start automatically. These chiller units are automatically sequenced on the EDG power supply in the event of loss of offsite electrical power.

The ventilation for the DG rooms is provided by separate air supply and exhaust systems for each room. During winter operations, a bypass damper is opened to allow recirculated air to be returned from the DG room to the inlet of the supply fan. When starting either or both DGs, the supply and exhaust systems will start automatically. During normal operations with the DGs not operating, ventilation to the rooms is supplied from the auxiliary building supply and exhaust ventilation system.

Two 100-percent capacity exhaust fans are provided to exhaust air from the various areas of the auxiliary building. Prefilters and high-efficiency particulate filters are provided on the outlet of the exhaust fans. The discharge from these units is directed to the plant stack.

Heating steam to coils in the HVAC units is supplied from the auxiliary steam system, and condensate is returned to the same system.

A separate ventilation system is provided for the waste evaporator enclosure on the roof of the auxiliary building. This system consists of a motor-operated outdoor air supply louver, filters, supply and exhaust fans, and an air distribution system. The exhaust fan discharges to the intake of the main exhaust units.

In Section 2.3.3.12 of the LRA, the applicant identified portions of the auxiliary building HVAC system and its SCs that are within the scope of license renewal and subject to an AMR. The applicant noted that the auxiliary building HVAC system is further described in Sections 9.4.4 and 9.4.8 of the UFSAR. The applicant identified the intended functions of the auxiliary building HVAC system based on 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3).

Section 2.3.3.12 of the LRA states that the auxiliary building HVAC system contains SCs that are safety related and are relied upon to remain functional during and following design-basis events, SCs that are relied on during postulated fires, and SCs that are part of the EQ Program.

Section 9.4 of the UFSAR states that the auxiliary building HVAC system is designed to remove the normal heat gain from the outdoors, equipment, lighting, and people; replace the normal heat lost to the outdoors; provide adequate ventilation for access requirements; and reduce the concentration of airborne radionuclides, nonradioactive particulate matter, and noxious gases.

On the basis of the intended functions as identified above for the auxiliary building HVAC system, the portions of these systems that were identified by the applicant as within the scope of license renewal include all of the auxiliary building HVAC safety-related components (electrical, mechanical, and instruments). The applicant described its methodology for identifying the mechanical components subject to an AMR in Section 2.1.2.1 of the LRA. On the basis of this scoping methodology, the applicant identified the portions of the auxiliary building HVAC system that are within scope on the flow diagrams listed in Section 2.3.3.12 of the LRA. Using the methodology described in Section 2.1.1 of the LRA, the applicant compiled a list of the mechanical components and component types subject to an AMR that are within the evaluation boundaries highlighted on the flow diagrams and identified their intended functions. The applicant provided this list in Table 2.3-18 of the LRA.

Closure bolting, ductwork, fittings, equipment frames, equipment housings, flexible collars, and heating/cooling coils are the component types identified in Table 2.3-18 of the LRA as within the scope of license renewal and subject to an AMR. The applicant further noted in Table 2.3-18 of the LRA that the auxiliary building HVAC system's intended function is to provide a pressure-retaining boundary so that sufficient flow at adequate pressure is delivered. An additional intended function is for the ductwork and fitting to provide structural support to safety-related components.

The applicant evaluated component supports for HVAC ductwork cited in Table 3.5-1 of the LRA. The applicant evaluated electrical components that support the operation of the auxiliary building HVAC system in Section 2.1.2.3 of the LRA. The staff's scoping and screening results of structures are provided in Section 2.4 of this SER. Electrical/I&C scoping and screening results of the auxiliary building HVAC system are provided in Section 2.5 of this SER.

2.3.3.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.12 and UFSAR Sections 9.4, 9.4.4, and 9.4.8 to determine whether there is reasonable assurance that the auxiliary building HVAC system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

To verify that the applicant identified the components of the auxiliary building HVAC system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1), the staff reviewed both the flow diagrams listed in Section 2.3.3.12 of the LRA that show the evaluation boundaries for the highlighted portions of the auxiliary building HVAC system that are within scope and Table 2.3-18 of the LRA which lists the mechanical components and the applicable intended functions that are subject to an AMR. The staff compared the functions described in the UFSAR to those identified in the LRA.

The applicant identified the SCs subject to an AMR for the auxiliary building HVAC system using the scoping and screening methodology described in Section 2.1 of the LRA and listed them in Table 2.3-18 of the LRA. The staff evaluated the scoping and screening methodology in Section 2.1 of this SER. The staff sampled components subject to an AMR. The staff also sampled the SCs that were within the scope of the LRA but not subject to an AMR. Based on this sample, the staff verified that these SCs performed their intended functions without moving parts or without a change in a configuration or properties and are not subject to replacement on the basis of a qualified life or specified time period.

To ensure that those portions of the auxiliary building HVAC system excluded from the scope of license renewal do not perform any intended functions, the staff requested additional information based on a review of the UFSAR and LRA descriptions. The staff noted that Section 2.3.3.12 of the LRA presents a summary description of the system functions and identified the system flow diagrams. The flow diagrams highlight the evaluation boundaries, and Table 2.3-18 of the LRA tabulates the components that are within scope and subject to an AMR for the auxiliary building HVAC system. The corresponding drawings and the UFSAR, however, show additional components that were not listed in Table 2.3-18 of the LRA.

In response to the staff's RAI, the applicant stated in a letter dated April 28, 2003, that ductwork in the auxiliary building HVAC system is subject to an AMR because it performs an intended function within the license renewal evaluation boundary, as shown on the flow diagram boundary drawings, and it is a passive component not subject to periodic replacement. The applicant also stated that ductwork is presently included in the component/commodity group "Equipment Frames and Housing" in LRA Table 2.3-19. To eliminate any confusion, the component/commodity group "Ductwork and Fittings" has been added to the HVAC control room area system, and the ductwork will be moved from the "Equipment Frames and Housing" group to the "Ductwork and Fittings" group. The staff finds this acceptable.

The staff noted that the applicant did not identify damper housings, ventilation system passive components, or structural sealants that require an AMR. The scoping and screening determination should consider whether failure of the damper housings, passive components, or structural sealants would result in a failure of the associated active components to perform their intended functions and whether the damper housings, passive components, or structural sealants meet the long-lived and passive criteria as defined in the rule.

The applicant's response in the April 28, 2003, letter stated that the system commodity "Ductwork" is also used to identify miscellaneous ductwork components that provide a pressure-retaining function. The licensee stated that ductwork includes ducts, fittings, access doors, equipment housings, flexible collars or connections, and seals.

Access doors, flexible connections, and seals were subject to AMR using the system commodity "Ductwork" grouping for untagged components in HVAC systems. Ductwork test connections are categorized as fittings. Therefore, ductwork test connections are included in the AMR result for the system commodity "Ductwork."

The licensee also stated that turning vanes are within the scope of license renewal and are subject to an AMR. Turning vanes are constructed of the same material as the duct in which they reside and are considered to be a subcomponent of the duct. Therefore, turning vanes are included in the AMR results for ductwork. The staff finds this acceptable.

Some components that are common to many systems, including the auxiliary building HVAC system, have been evaluated separately by the applicant in Section 2.1.2 of the LRA as consumables. The staff noted that the applicant should reference the latest consumable guidance provided in the License Renewal Standard Review Plan, dated April 2001 (NUREG-1800, Table 2.1-3).

In a letter dated April 28, 2003, the licensee stated that the evaluation process used to evaluate consumables is consistent with the guidance provided in NUREG-1800, Table 2.1-3. The staff finds this acceptable.

The staff evaluated component supports for piping, cables, and equipment, which are discussed in Section 2.4 of the LRA titled, "Scoping and Screening Results—Structures." In Section 2.5 of this report, the staff evaluated electrical and instrumentation components that support the operation of the auxiliary building HVAC system, which are discussed in Section 2.5 of the LRA, titled "Scoping and Screening Results—Electrical and Instrumentation and Controls."

The staff reviewed the LRA, supporting information in the UFSAR, and the applicant's response to RAIs. In addition, the staff sampled several components from the auxiliary building HVAC system flow diagram, as identified in Section 2.3.3.12 of the LRA, to determine whether the applicant properly identified the components within scope and subject to an AMR.

2.3.3.12.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the components of the auxiliary building HVAC system that are within the scope of license renewal, as required by

10 CFR 54.4(a), and that the applicant has appropriately identified the components of the auxiliary building HVAC system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.13 Heating, Ventilation, and Air Conditioning—Control Room Area

2.3.3.13.1 Summary of Technical Information in the Application

The applicant described the control room area HVAC in LRA Section 2.3.3.13 and provided a list of components subject to an AMR in LRA Table 2.3-19.

The RNP control room area HVAC system consists of an environmental control system and an air cleanup system to serve the control room. The primary purpose of the control room HVAC system is to provide heating, ventilation, cooling, filtration, air intake, and exhaust isolation during normal operation and a DBA.

The control room HVAC comprises two parts, an environmental control system and an air cleanup system. The system is safety related, and redundancy is provided for safety-related active components.

The environmental control system continually operates during normal and emergency conditions. This system consists of redundant 100-percent capacity fans and gravity dampers arranged in parallel and a stainless steel housing containing a medium-efficiency filter and redundant 100-percent capacity direct expansion cooling coils. Redundant 100-percent capacity service water cooled condensing units are provided, one connected by refrigerant piping to each cooling coil. Redundant safety-related equipment and controls are powered from separate safety-related power supplies. The air cleanup system normally operates only during emergency conditions. This system consists of redundant 100-percent capacity fans and gravity dampers arranged in parallel and a stainless steel housing containing a prefilter, a pre-HEPA charcoal adsorber, and post-HEPA filter banks.

The control room air conditioning system consists of a single outside air intake with the connecting duct containing parallel and redundant air-operated control dampers. The control room kitchen and toilet exhaust duct contains redundant air-operated control dampers in series. All air-operated control dampers are designed to fail to safe positions following a loss of IA supply or electric power, and redundancy is provided for single failure protection.

In Section 2.3.3.13 of the LRA, the applicant identified portions of the control room area HVAC system and its SCs that are within the scope of license renewal and subject to an AMR. The applicant noted in Section 2.3.3.13 of the LRA that the control area HVAC system is further described in Section 9.4.2 of the UFSAR. The applicant identified the following intended functions of the RNP control room area HVAC system based on 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3).

Section 2.3.3.13 of the LRA states that the control room area HVAC system contains structures and components that are safety related and are relied upon to remain functional during and following design-basis events and structures and components that are relied on during postulated fires.

Section 9.4.2.1 of the UFSAR states that the control room area HVAC system is designed to perform the following functions:

- maintain the control room at a design temperature within limits, assuring personnel comfort as well as a suitable environment for continuous operation of controls and instrumentation

- detect the introduction of radioactive material into the control room and automatically place the system into the emergency pressurization mode of operation following a safety injection or high-radiation signal

- remove airborne radioactivity from the control room envelope and outside air makeup to the extent that dose to the control room operator following a design-basis accident does not exceed the limit specified in General Design Criterion 19
- be powered by the redundant emergency buses

- remain operable following any single active component failure or following a failure in a single emergency power supply coincident with the loss of offsite power

- meet the seismic Category 1 requirements for all safety-related system components

On the basis of the intended functions identified above for the control room area HVAC system, the portions of these systems that were identified by the applicant as within the scope of the application include all of the control room area HVAC system safety-related components (electrical, mechanical, and instruments). The applicant described its methodology for identifying the mechanical components subject to an AMR in Section 2.1.2.1 of the LRA. On the basis of this scoping methodology, the applicant identified the portions of the control room area HVAC system that are within scope on the flow diagram listed in Section 2.3.3.13 of the LRA. Using the methodology described in Section 2.1.1 of the LRA, the applicant compiled a list of the mechanical components and component types subject to an AMR that are within the evaluation boundaries highlighted on the flow diagram and identified their intended functions. The applicant provided this list in Table 2.3-19 of the LRA.

The component types identified as within the scope of license renewal and subject to an AMR within Table 2.3-19 of the LRA include closure bolting, equipment frames, equipment housings, flexible collars, flow orifices/elements, heating/cooling coils, valves, piping, tubing, and fittings. The applicant noted in Table 2.3-19 of the LRA that the control room area HVAC system intended functions include the pressure-retaining boundary, structural support, heat transfer, and flow restriction functions.

The applicant evaluated component supports for HVAC ductwork cited in Table 3.5-1 of the LRA. The applicant evaluated electrical components that support the operation of the control room area HVAC system in Section 2.1.2.3 of the LRA. The staff's scoping and screening results for structures are provided in Section 2.4 of this SER. Electrical/I&C scoping and screening results for the control room area HVAC system are provided in Section 2.5 of this SER.

2.3.3.13.2 Staff Evaluation

The staff reviewed LRA Section 2.3.13 and UFSAR Section 9.4.2 to determine whether there is reasonable assurance that the control room area HVAC components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

To verify that the applicant identified the components of the control room area HVAC system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1), the staff reviewed the flow diagram listed in Section 2.3.3.13 of the LRA that shows the evaluation boundaries for the highlighted portions of the control room area HVAC system that are within scope and Table 2.3-19 of the LRA, which lists the mechanical components and the applicable intended functions that are subject to an AMR. The staff also reviewed Section 9.4.2 of the UFSAR to determine if there were any portions of the control room area HVAC system that met the scoping criteria in 10 CFR 54.4(a) but were not identified as within the scope. The staff reviewed the UFSAR also to determine if there were any safety-related system functions that were not identified as an intended function in the LRA and to determine if there were any structures or components that have an intended function that might have been omitted from the scope of structures or components that require an AMR. The staff compared the functions described in the UFSAR to those identified in the LRA.

The applicant identified the SCs subject to an AMR for the control room area HVAC system using the scoping and screening methodology described in Section 2.1 of the LRA and listed them in Table 2.3-19 of the LRA. The staff evaluated the scoping and screening methodology in Section 2.1 of this SER. The staff sampled components subject to an AMR. The staff also sampled the SCs that were within the scope of the LRA but not subject to an AMR. Based on this sample, the staff verified that these SCs performed their intended functions without moving parts or without a change in configuration or properties and are not subject to replacement on the basis of a qualified life or specified time period.

To ensure that those portions of the control room area HVAC system excluded from the scope of license renewal do not perform any intended functions, the staff requested additional information based on a review of the UFSAR and LRA descriptions. The staff noted that Section 2.3.3.13 of the LRA presents a summary description of the system functions and identified a corresponding system flow diagram. The flow diagram highlights the evaluation boundaries, and Table 2.3-19 of the LRA tabulates the components within scope and subject to an AMR for the control room area HVAC system. The corresponding drawings and UFSAR, however, show additional components that were not listed in Table 2.3-19 of the LRA.

In an RAI, the NRC staff stated that the ventilation systems used to support use of the safe shutdown controls have not been included as part of the scoping and screening process. In a letter dated April 28, 2003, the applicant stated that RAB HVAC and control room HVAC systems are in scope for license renewal and are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection. The applicant further stated that plant shutdown from the safe shutdown controls is accomplished as described in UFSAR Section 7.4.1.1 and UFSAR Appendix 9.5.1A. Section III.G of 10 CFR 50 Appendix R, "Safe Shutdown Components/Cable Separation Analysis," documents the evaluation performed for the Appendix R ventilation support function and the acceptability of existing analyses that demonstrate that safe shutdown requirements can be satisfied.

The applicant also stated that no other ventilation systems support the use of the safe shutdown controls. Safe shutdown control panels in the turbine building do not need HVAC because of the open design of the turbine building. Therefore, ventilation systems used to support the safe shutdown controls are in the scope of license renewal and subject to an AMR. The staff finds this acceptable.

The staff noted that the applicant did not identify damper housings, ductwork, ventilation system passive components, or structural sealants that require an AMR. The scoping and screening determination should consider whether failure of the damper housings, ductwork, passive components, or structural sealants would result in a failure of the associated active components to perform their intended functions and whether the damper housings, ductwork, passive components, or structural sealants meet the long-lived and passive criteria as defined in the rule. The applicant's response in the April 28, 2003, letter stated that system commodity "Ductwork" is also used to identify miscellaneous ductwork components that provide a pressure-retaining function. The licensee stated that ductwork includes ducts, fittings, access doors, equipment housings, flexible collars or connections, and seals.

Access doors, flexible connections, and seals were subject to AMR using the system commodity "Ductwork" grouping for untagged components in HVAC systems. Ductwork test connections are categorized as fittings. Therefore, ductwork test connections are included in the aging management review results for the system commodity "Ductwork."

The licensee also stated that turning vanes are within the scope of license renewal and are subject to an AMR. Turning vanes are constructed of the same material as the duct in which they reside and are considered to be a subcomponent of the duct. Therefore, turning vanes are included in the AMR results for ductwork. The staff finds this acceptable.

Some components that are common to many systems, including the control room area HVAC system, have been evaluated separately by the applicant in Section 2.1.2 of the LRA as consumables. The staff noted that the applicant should reference the latest consumable guidance provided in the License Renewal Standard Review Plan, dated April 2001 (NUREG-1800, Table 2.1-3).

In a letter dated April 28, 2003, the licensee stated that the evaluation process used to evaluate consumables is consistent with the guidance provided in NUREG-1800, Table 2.1-3. The staff finds this acceptable.

The staff evaluated component support for piping, cables, and equipment, which are discussed in Section 2.4 of the LRA, titled "Scoping and Screening Results—Structures." In Section 2.5 of this report, the staff evaluated electrical and instrumentation components that support the operation of the control room area HVAC system, which are discussed in Section 2.5 of the LRA, titled "Scoping and Screening Results—Electrical and Instrumentation and Controls."

The staff reviewed the LRA, supporting information in the UFSAR, and the applicant's response to RAIs. In addition, the staff sampled several components from the control room area HVAC system flow diagram as identified in Section 2.3.3.13 of the LRA to determine whether the applicant properly identified the components within scope and subject to an AMR.

2.3.3.13.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the components of the control room area HVAC systems that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has appropriately identified the components of the control room area HVAC systems that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.14 Heating, Ventilation, and Air Conditioning—Fuel Handling Building

2.3.3.14.1 Summary of Technical Information in the Application

The applicant describes the HVAC system for the fuel handling building (FHB) in LRA Section 2.3.3.14 and provides a list of components subject to an AMR in LRA Table 2.3-20.

The FHB HVAC system provides ventilation and heat removal for the fuel handling building. The primary purpose of the FHB HVAC system is to provide clean air to the operating areas of the building and then filter and exhaust air from both the equipment rooms and open areas of the building.

Ventilation and cooling of the various areas in the FHB are accomplished with a continuous supply of treated outdoor air from two supply air units to various areas within the building, inter area air transfer from areas of lower contamination to areas of higher contamination, and three independent air exhaust systems.

The ventilation air supply system consists of two air handling units. Each air handling unit consists of prefilters, steam heating coils, and a centrifugal fan enclosed by a sheet metal casing. The air intake of these units is connected to dampered outdoor air louvers, and the supply air is discharged into an air distribution system. The direction of air flow is always from areas of lower contamination to areas of higher contamination.

In Section 2.3.3.14 of the LRA the applicant identified portions of the FHB HVAC system and its SCs that are within the scope of license renewal and subject to an AMR. The applicant noted in Section 2.3.3.14 of the LRA that the FHB HVAC system is further described in Section 9.4.5 of the RNP UFSAR. The applicant identified the following intended functions of the FHB HVAC system based on 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2):

- structures and components that are safety related and are relied upon to remain functional during and following design-basis events (LRA Section 2.3.3.14)
- structures and components that are relied on during postulated fires, (LRA Section 2.3.3.11)
- provide ventilation and cooling of the various areas in the fuel handling building, (UFSAR Section 9.4.3.4)

On the basis of the intended functions identified above for the FHB HVAC system, the portions of the system that were identified by the applicant as within the scope of the application include all of the system safety-related components (electrical, mechanical, and instruments). The applicant described its methodology for identifying the mechanical components subject to an AMR in Section 2.1.2.1 of the LRA. On the basis of this scoping methodology, the applicant identified the portions of the system that are within scope on the flow diagram listed in Section 2.3.3.14 of the LRA. Using the methodology described in Section 2.1.1 of the LRA, the applicant compiled a list of the mechanical components and component types subject to an AMR that are within the evaluation boundaries highlighted on the flow diagram and identified their intended functions. The applicant provided this list in Table 2.3-20 of the LRA.

The component types identified as within the scope of license renewal and subject to an AMR and listed in Table 2.3-20 of the LRA include closure bolting, ductwork, fittings, equipment frames, equipment housings, and flexible collars. The applicant further noted in Table 2.3-20 of the LRA that the FHB HVAC system intended functions are to provide a pressure-retaining boundary so that sufficient flow at adequate pressure is delivered and to provide structural support to safety-related components.

The applicant evaluated component supports for HVAC ductwork cited in Table 3.5-1 of the LRA. The applicant evaluated electrical components that support the operation of the FHB HVAC system in Section 2.1.2.3 of the LRA. The staff's scoping and screening results for structures are provided in Section 2.4 of this SER. Scoping and screening results for electrical/I&C for the FHB HVAC system are provided in Section 2.5 of this SER.

2.3.3.14.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.14 and UFSAR Sections 9.4.1 and 9.4.5 to determine whether there is reasonable assurance that the FHB HVAC system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of its review, the staff selected system functions described in the UFSAR that are required by 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

To verify that the applicant identified the components of the FHB HVAC system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1), the staff reviewed the flow diagram listed in Section 2.3.3.14 of the LRA that shows the evaluation boundaries for the highlighted portions of the FHB HVAC system that are within scope and Table 2.3-14 of the LRA, which lists the mechanical components and the applicable intended functions that are subject to an AMR. The staff also reviewed Section 9.4.5 of the UFSAR to determine if there were any portions of the FHB HVAC system that met the scoping criteria in 10 CFR 54.4(a) but were not identified as within the scope. The staff also reviewed the UFSAR to determine if there were any safety-related system functions that were not identified as an intended function in the LRA to determine if there were any structures or components that have an intended function that might have been omitted from the scope of structures or components that require an AMR. The staff compared the functions described in the UFSAR to those identified in the LRA.

The applicant identified the SCs subject to an AMR for the FHB HVAC system using the scoping and screening methodology described in Section 2.1 of the LRA and listed them in Table 2.3-20 of the LRA. The staff evaluated the scoping and screening methodology in Section 2.1 of this SER. The staff sampled components subject to an AMR. The staff also sampled the SCs that were within the scope of the LRA but not subject to an AMR. Based on this sample, the staff verified that these SCs performed their intended functions without moving parts or without a change in configuration or properties and are not subject to replacement on the basis of a qualified life or specified time period.

To ensure that those portions of the FHB HVAC system excluded from the scope of license renewal do not perform any intended functions, the staff requested additional information based on a review of the UFSAR and LRA descriptions. The staff noted that Section 2.3.3.14 of the LRA presents a summary description of the system functions and identified a corresponding system flow diagram. The flow diagram highlights the evaluation boundaries, and Table 2.3-20 of the LRA tabulates the components within scope and subject to an AMR for the FHB HVAC system. The corresponding drawings and UFSAR, however, show additional components that were not listed in Table 2.3-20 of the LRA.

An NRC staff RAI stated that fans HVE-14, HVE-15, and HVE-21 and their associated ductwork, fan housing, filters, and components are excluded from the scope of license renewal and that the applicant should state whether these fans and their associated components are subject to an AMR. In response, by letter dated April 28, 2003, the applicant stated that the identified fans and their associated components are not subject to an AMR because the components do not perform a license renewal intended function. The intended function for the FHB HVAC system is to mitigate the consequences of a fuel handling accident inside the FHB to ensure that radioactive releases do not result in offsite exposures greater than the guidelines provided by 10 CFR Part 100. The listed components are not required to accomplish the intended function. The staff finds this acceptable.

The staff noted that the applicant did not identify damper housings, ventilation system passive components, or structural sealants that require an AMR. The scoping and screening determination should consider whether failure of the damper housings, passive components, or structural sealants would result in a failure of the associated active components to perform their intended functions and whether the damper housings, passive components, or structural sealants meet the long-lived and passive criteria as defined in the Rule.

By letter dated April 28, 2003, the applicant provided information stating that ventilation dampers are within the scope of license renewal. The system commodity "Damper Housings" is used to identify damper housings within the scope of license renewal that provide a structural support function. The system commodity "Ductwork" is used to identify damper equipment housings within the scope of license renewal that provide a pressure boundary function.

The applicant, in its April 28, 2003, letter, stated that system commodity "Ductwork" is also used to identify miscellaneous ductwork components that provide a pressure-retaining function. The licensee stated that ductwork includes ducts, fittings, access doors, equipment housings, flexible collars or connections, and seals.

Access doors, flexible connections, and seals were subject to AMR using the system commodity "Ductwork" grouping for untagged components in HVAC systems. Ductwork test connections are categorized as fittings. Therefore, ductwork test connections are included in the aging management review result for the system commodity "Ductwork."

The licensee also stated that turning vanes are within the scope of license renewal and are subject to an AMR. Turning vanes are constructed of the same material as the duct in which they reside and are considered to be a subcomponent of the duct. Therefore, turning vanes are included in the AMR results for ductwork. The staff finds this acceptable.

Some components that are common to many systems, including the fuel handling building HVAC system, have been evaluated separately by the applicant in Section 2.1.2 of the LRA as consumables. The staff noted that the applicant should reference the latest consumable guidance provided in the License Renewal Standard Review Plan, dated April 2001 (Reference: NUREG-1800, Table 2.1-3).

In a letter dated April 28, 2003, the licensee stated that the evaluation process used to evaluate consumables is consistent with the guidance provided in NUREG-1800, Table 2.1-3. The staff finds this acceptable.

The staff evaluated component supports for piping, cables, and equipment, which are discussed in Section 2.4 of the LRA titled, "Scoping and Screening Results—Structures." In Section 2.5 of this report the staff evaluated electrical and instrumentation components that support the operation of the fuel handling building HVAC system, which are discussed in Section 2.5 of the LRA titled, "Scoping and Screening Results—Electrical and Instrumentation and Controls (I&C) Systems."

The staff reviewed the LRA, supporting information in the UFSAR, and the applicant's response to RAIs. In addition, the staff sampled several components from the fuel handling building HVAC system flow diagram, as identified in Section 2.3.3.14 of the LRA, to determine whether the applicant properly identified the components within scope and subject to an AMR.

2.3.3.14.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has appropriately identified the components of the FHB HVAC system that are within the scope of license renewal, as required by 10 CFR 54.4 (a), and that the applicant has appropriately identified the components of the FHB HVAC system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.15 Fire Protection System

2.3.3.15.1 Summary of Technical Information in the Application

The applicant describes the FP systems in LRA Section 2.3.3.15, "Fire Protection System," and provides a list of components subject to an AMR in LRA Table 2.3-21.

In LRA Section 2.3.3.15, the applicant identifies the SCs at RNP that support either FP design or safe shutdown following a fire that are considered within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) and subject to an AMR. In LRA Section 2.3.3.15, the applicant identifies and describes the systems and components that are within the scope of license renewal. The applicant also describes the criteria for including the FP system in the scope of license renewal and its methodology for including components in the LRA. LRA Table 2.3-21 lists the components and commodities that have been identified by the applicant as requiring AMR. LRA Tables 3.3-1 and 3.3-2 include the aging management evaluations.

During preliminary discussions with the applicant, the staff determined that additional information regarding the fire suppression systems (system drawings and system descriptions) should be included in the application. The applicant responded in a letter dated August 14, 2002, with the additional information requested. By letter dated October 23, 2002, the applicant responded to the draft interim staff guidance (ISG-04) regarding aging management of FP systems for license renewal (ADAMS Accession No. ML023440137).

By letter dated February 11, 2003, the staff issued the final RAI letter regarding FP SCs, which is discussed in Section 2.3.3.15.2. By letter dated April 28, 2003, the applicant responded to that RAI. By letter dated June 13, 2003, the applicant provided supplemental information regarding the LRA.

According to 10 CFR 54.4(a)(3), all SSCs relied upon in safety analyses or plant evaluation to perform a function that demonstrates compliance with the Commission's regulations in 10 CFR 50.48, "Fire Protection," must be included within the scope of license renewal. As required by 10 CFR 50.48, the applicant must implement and maintain an FP program. The applicant used its Passport Equipment Database, UFSAR Section 9.5.1, UFSAR Appendices 9.5.1A, 9.5.1B, and 9.5.1C, design drawings, and component databases to determine the SSCs relied on for FP to meet 10 CFR 54.4(a)(3).

In Section 2.1.1.3.1 of the LRA, the applicant identifies the methodology for including SSCs in the LRA.

The purpose of the FP system is to protect plant equipment in the event of a fire to ensure safe plant shutdown and minimize the risk of a radioactive release to the environment. The FP systems consist of fire suppression systems (water, Halon 1301, carbon dioxide (CO_2) and portable extinguishers), fire detection systems, and fire barrier systems.

The fire water supply system has fire pumps that draw water from Lake Robinson. A pressure maintenance pump (jockey pump) provides normal pressurization to the fire water supply system. The fire water supply system feeds fixed manual suppression systems, such as hydrants and fire hose stations, and wet pipe, deluge, and preaction sprinkler systems throughout the RNP. The manual hose stations serve as backup protection in areas where automatic suppression (water based or gaseous) is installed. Gaseous FP systems (Halon 1301 and CO_2) are installed in areas where non-water-based fire suppressant agents are preferred. Portable extinguishers are provided at strategic locations throughout the plant as described in the fire hazards analysis (FHA) portion of the UFSAR.

The fire detection system continuously monitors for the presence of fire, promptly alarms in the event of a fire, actuates certain automatic fixed FP systems, and, in some areas, provides auxiliary functions such as closing ventilation system dampers. Smoke, heat, and flame fire detection devices are located throughout the plant. Local fire alarm panels will alarm and indicate the affected fire detection zone. Also, the alarms will be received in the control room and be displayed in the control room and/or the control room vestibule.

Fire barriers are used at RNP to divide buildings into fire zones and fire areas to prevent fire propagation. Barriers, such as walls, ceilings, floors, doors, dampers, and penetration seals, are installed to limit fire propagation from area to area. Other features limit fire propagation and control damage. These features are radiant energy shields, curbs, dikes, and flame-retardant coatings.

On the basis of the methodology described above, the applicant identifies the highlighted portions of the flow diagrams, "License Renewal Boundary Drawings," which were provided with the August 14, 2002, letter, as the boundaries of the portions of the FP water-based system that are included within the scope of license renewal. Non-water-based FP systems were not provided on boundary drawings; rather, they were included in system descriptions that were also provided in the August 14, 2002, letter.

In LRA Section 2.3.3.15, the applicant identifies the following FP system components as within the scope of license renewal and subject to an AMR:

- closure bolting
- diesel-driven and motor-driven fire pumps
- ductwork and fittings
- fire hydrants
- flow orifices and elements
- jockey pump
- sprinklers
- valves, piping, tubing, and fittings

The intended functions of the FP mechanical components identified by the applicant are pressure boundary integrity, structural support, flow restriction (throttle), and filtration. In LRA Table 2.3-21, the applicant lists the mechanical components and their respective intended functions.

2.3.3.15.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.15, UFSAR Section 9.5.1, and UFSAR Section 9.5.1 Appendices A, B, and C, to determine whether there is reasonable assurance that the fire protection system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted. Commitments to 10 CFR Part 50, Appendix R, are described in the UFSAR. The staff sampled portions of the UFSAR to identify any additional FP system function that meets the scoping requirements of 10 CFR 54.4 but was not identified as an intended function in the LRA.

The staff also reviewed the SER referenced for the FP program, which was listed directly in the RNP license condition. This SER summarizes the FP program and commitments made to meet 10 CFR 50.48 using the guidelines of Appendix A to Branch Technical Position (BTP) Auxiliary Power Conversion Systems Branch (APCSB) 9.5-1. The staff sampled portions of this SER to verify that the functions of the FP components relied upon to satisfy the provisions of Appendix A to BTP APCSB 9.5-1 were included within the scope of license renewal as intended functions in the LRA.

The FP system is within the scope of license renewal, as described in LRA Section 2.3.3.15, because it contains the following types of components:

- SCs that are safety related and are relied upon to remain functional during and following design-basis events
- SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are part of the Environmental Qualification Program
- SCs that are relied on during postulated fires

In LRA Section 2.3.3.15, the applicant states that flow diagrams were not prepared to show the evaluation boundaries for the portions of the FP system that are within the scope of license renewal. The applicant scoped the FP systems by using plant documents and functional classifications in the equipment databases. The plant documents were not provided in the application. Flow diagrams were provided for the fuel oil system as described in LRA Section 2.3.3.19. The staff questioned the lack of review material during preliminary discussions, and the applicant, in a letter sent August 14, 2002, delivered FP boundary drawings for the water systems, consisting of the flow diagrams for the FP systems highlighted to show the portions of this system that are within the scope of license renewal. For the nonwater FP systems, lists of relevant portions of the equipment database and system descriptions were provided for staff review.

The safe shutdown equipment required for compliance with 10 CFR Part 50, Appendix R, was screened with its respective systems and therefore is not addressed in this section of the LRA. A sampling review of the equipment listed in UFSAR Section 9.5.1C, "Safe Shutdown Analysis," did not identify any SSCs missing from scoping.

The staff sampled portions of the applicant's UFSAR Section 9.5.1, "Fire Protection System," and Appendices 9.5.1A, "Fire Hazards Analysis," 9.5.1B, "Fire Protection Program Description and Review Per Appendix A to BTP APCSB 9.5-1," and 9.5.1C, "Safe-Shutdown Analysis," which contains plant commitments and safety evaluations that form the basis of the FP program at RNP. The staff then compared a sample of the FP systems and components identified within the UFSAR to the FP system flow diagrams and equipment lists to verify that required components were identified within the evaluation boundaries of the flow diagram or included in equipment lists and were not excluded from the scope of license renewal.

The staff also compared SSCs identified in the NRC-approved SER, which documents the applicant's compliance with provisions of Appendix A to BTP APCSB 9.5-1, "Fire Protection for Nuclear Power Plants," to the FP system flow diagrams to verify if portions of the FP system were inadvertently excluded from within the scope of license renewal.

In Appendix 9.5.1B of the UFSAR, the applicant provides a discussion of its "compliance with the intent" of Appendix A to BTP APCSB 9.5-1. Since RNP was licensed prior to 1979, Section III.G, III.J, and III.L of 10 CFR Part 50, Appendix R, also apply. The UFSAR contains the analysis to demonstrate compliance with 10 CFR Part 50, Appendix R, and with Appendix A to BTP APCSB 9.5-1.

The applicant has committed to meet the guidelines provided in Attachment 6, "Quality Assurance," of the August 4, 1977, NRC letter titled "Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls and Quality Assurance." The quality assurance program at RNP for FP systems is in effect as described in UFSAR Section 17, as outlined in the CP&L Corporate Quality Assurance Manual.

The staff reviewed the applicant's submittal and the UFSAR to verify that required components of the FP systems were included within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4 and 54.21(a)(1).

In a letter dated February 11, 2003, the staff transmitted the final RAI letter to the applicant regarding the exclusion from the LRA of some FP components that either are part of the plant's CLB or required to demonstrate compliance with 10 CFR 50.48.

During a meeting on October 24, 2002, the applicant clarified that the jockey fire pump, as listed in LRA Table 2.3-21, is the fire water booster pump as shown on drawing HBR2-8255LR, sheet 1.

In a letter dated April 28, 2003, in response to RAI 2.3.3.15-1, the applicant clarified that fire hose is considered to be a consumable, consistent with other consumables listed after LRA Table 2.3-21. The applicant will replace fire hoses in accordance with National Fire Protection Association (NFPA) guidance.

In response to RAI 2.3.3.15-2, the applicant provides a basis for the exclusion of the Unit 1 fire water loop from the scope of license renewal. The explanation that although the Unit 1 fire water loop is available as a viable backup to the Unit 2 fire water pumps and the 1978 SER described the availability of this backup function, the applicant concludes that the Unit 1 system is not required to comply with NRC FP regulations. The staff has reviewed the applicant's basis and considers the fire water system compliant with the regulation without the Unit 1 fire water loop, and therefore finds acceptable the exclusion of the Unit 1 fire water loop from scope.

In response to RAI 2.3.3.15-3, the applicant provides a basis for the exclusion of selected turbine building local application fire suppression systems from the LRA scope. In its RAI response, the applicant confirms that dedicated shutdown (DS) cables are routed on the outside of the turbine building. The applicant explains that even with the loss of the turbine building or transformer yard, the motor-driven AFW pumps and sufficient power distribution would remain available to safely shut down the plant. The staff has reviewed the applicant's basis for excluding these water suppression systems and, based on the RAI response, concurs that these systems predate the safe shutdown systems (i.e., the excluded systems were installed for insurance purposes only). The applicant's letter of June 13, 2003, provides additional information regarding this item. In the letter the applicant states that the fire hydrants are credited with protecting the dedicated shutdown cables and that the hydrants are within the scope of license renewal. Therefore, the staff finds that excluding these systems from scope is acceptable.

In response to RAI 2.3.3.15-4, the applicant clarified that the concrete barrier separation between RHR pumps in the RHR pit is included as a "Civil Concrete" commodity in LRA Table 3.5-1, Item 16.

Regarding RAI 2.3.3.15-5, during a meeting on May 20, 2003, the staff explained a concern about the applicant's ability to identify and isolate a leak prior to excessive water discharge due to an aging-related failure. By letter dated June 13, 2003, the applicant agreed to include the piping to the closed valve within the scope of license renewal for FP systems at or around the power block, including the spent fuel pit area and transformer area. For the FP for other site buildings, the applicant has expanded the scoping boundaries such that the boundaries are at the site building. The applicant provides four points to support this position. First, relatively large bore piping will be included within scope. Second, significant leakage would be identified since the site buildings are subject to ongoing observation. Third, leakage would be readily detected and resolved. Fourth, system design does not always provide an easily identified valve for isolation. The staff has reviewed this analysis and considers that this approach, flagging the license renewal boundaries at closed valves in the power block and at the entrance to the structure for site buildings, would quickly identify and isolate a leak. Therefore, the staff finds the resolution of this RAI acceptable.

In response to RAI 2.3.3.15-6, the applicant clarifies that Halon 1301 fire extinguishing agent cylinder assemblies are included in LRA Table 2.3-21, as part of the "Valves, Piping and Fittings" commodity group, and therefore were subject to an AMR as described in LRA Table 3.3-2, Item 19.

In response to RAI 2.3.3.15-7, the applicant clarified that CO_2 cylinders used to store CO_2 for FP systems are included in LRA Table 2.3-21, in the component/commodity group of "Valves, Piping and Fittings." The aging management of these cylinders is consistent with the aging management for similar materials.

In response to RAI 2.3.3.15-8, the applicant identified that the CO_2 system's heat actuated devices (HADs) were not presently identified in the LRA. The applicant applied its screening criteria to the tubing related to the HADs and determined that the tubing will be considered within the scope of license renewal and subject to an AMR. The staff has reviewed the scoping and AMR and finds it acceptable.

In response to RAI 2.3.3.15-9, the applicant confirms that both the electric and diesel power fire pumps have strainers. Although these nonferrous strainers were initially excluded from aging management since the applicant considered them part of the pump, upon further review, these strainers have been accorded the "provides filtration" intended function and will be managed against the effects of aging. The management shall include periodic removal, refurbishment, and replacement as specified by the RNP Preventive Maintenance Aging Management Program (PMAMP). The staff has reviewed the response to RAI 2.3.3.15-9, and since the strainers will be added to the scope of license renewal and shall be inspected under the PMAMP, the staff finds this acceptable.

In response to RAI 2.3.3.15-10, the applicant states that the flame-retardant coatings have been added to the license renewal scope and the AMR has been updated to evaluate flame-retardant coatings. The aging effect, "loss of material due to flaking," will be monitored through the PMAMP. The applicant clarified in the letter dated June 13, 2003, that cables inside containment in the cable penetration area were not coated and instead a suppression system was installed (see the letter dated January 28, 1980, from E.E. Utley to A. Schwencer (Public Legacy Library No. 8001310299). The staff has evaluated the addition of flame-retardant coating to the scope of license renewal and the AMP and finds this acceptable.

In response to RAI 2.3.3-15-11, the applicant referred to the fact that the fire protective wrap for the fuel oil makeup line is no longer credited. The applicant further clarified that the 3-hour barrier for the "B" diesel generator service water line is included within the scope of license renewal as part of LRA Tables 2.4-2 and 2.4-3, and the AMR results are included in LRA Table 3.3-1, Item 19.

After the staff determined which SCs were within the scope of license renewal, the staff determined whether the applicant properly selected the components subject to an AMR from among those identified as being within the scope of license renewal. The staff reviewed selected components that the applicant had identified as being within the scope of license renewal to verify that the applicant had identified these components as subject to an AMR if they perform intended functions without moving parts or without a change in configuration or properties and are not subject to replacement on the basis of a qualified life or specified time period. The staff did not identify any other omissions of passive and long-lived components that are required for 10 CFR 50.48 compliance.

2.3.3.15.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the FP system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the FP system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.16 Diesel Generator System

2.3.3.16.1 Summary of Technical Information in the Application

The applicant describes the diesel generator system (DGS) in LRA Section 2.3.3.16 and provides a list of components subject to an AMR in LRA Table 2.3-22.

The DGS provides AC power to the onsite electrical distribution system for plant shutdown. The DGS comprises two diesel generators and seven support systems necessary for proper operation of the diesel generators. These support systems consist of the starting air, the lube oil, the jacket water cooling, the scavenging air, the scavenging air cooling, the diesel engine fuel oil, and the diesel exhaust subsystems.

In LRA Table 2.3-22, the applicant identified the following components from the DGS as being within the scope of license renewal and subject to an AMR (1) after coolant heat exchangers shell, shell and waterbox cover, tube sheet, tubing, waterbox, and waterbox cover, (2) jacket water and after coolant regulators body/bonnet, (3) jacket water heat exchangers shell, shell and waterbox cover, tube sheet, tubing, waterbox, and waterbox cover, (4) jacket water standby heater shell, (5) lube oil heat exchangers tube sheet, tubing, waterbox, water box cover, shell, shell and water box cover, filters, heaters shell, strainers, and recirculation standby pump, (6) standby circulating coolant pump, (7) main bearing oil booster regulators body/bonnet, (8) air supply regulators to jacking gear body/bonnet, (9) pre lube oil pump, (10) air exhaust silencer, (11) air intake silencer filters, (12) air start strainers, (13) air receiver tanks, (14) jacket water expansion tanks, (15) flow orifices elements, (16) starting air compressor unloaders regulator body/bonnet, and (17) valves, piping, tubing, and fittings.

The applicant stated that the intended function common to all components is to provide pressure-retaining boundary so that sufficient flow at adequate pressure is delivered. Other intended functions, as stated, are to provide heat transfer (after coolant, jacket water, and lube oil heat exchanger tubing); filtration (lube oil strainers, air start strainers, valves, piping, tubing, and fittings); structural support to safety-related components (air exhaust silencer, air intake silencer filters, starting air compressor, unloaders, regulator body/bonnet, valves, piping, tubing, and fittings); and flow restriction (flow orifices/elements).

2.3.3.16.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.16 and UFSAR Section 8.3.1.1.5 to determine whether there is reasonable assurance that the DGS components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not

omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The staff's review of the applicant's scoping results did not identify the omission of any components needed to support the performance of the DGS's intended functions. The staff also found that the applicant adequately identified in LRA Table 2.3-22 those long-lived, passive components of the DGS considered to be within the scope of license renewal.

2.3.3.16.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the DGS that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the DGS that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.17 Dedicated Shutdown Diesel Generator

2.3.3.17.1 Summary of Technical Information in the Application

The applicant describes the dedicated shutdown diesel generator (DSDG) in LRA Section 2.3.3.17 and provides a list of components subject to an AMR in LRA Table 2.3-23.

The DSDG is relied on during postulated fires and also serves as the alternate alternating current supply during a station blackout.

In Table 2.3-23, the applicant identified the following components from the DSDG as being within the scope of license renewal and subject to an AMR (1) air exhaust silencer, (2) air vacuum box filter, (3) air volume tank, (4) expansion tank, (5) immersion heater, (6) lube oil circulating pump, cooler shell, cooler tubing and channels, cooler channel and shell, cooler tubing and fins, filter, and strainer, (7) radiator tubing and water box, (8) soak back oil filter, (9) turbo charger oil filter and soak back pump, (10) air compressor filter, (11) duct work and fittings, and (12) valves, piping, tubing, and fittings.

The applicant stated that the intended function common to all components is to provide pressure-retaining boundary so that sufficient flow at adequate pressure is delivered. Other intended functions of selected components are, as stated, to provide filtration (lube oil strainer), heat transfer (lube oil cooler tubing and channels, lube oil cooler tubing and fins, and radiator tubing), flow restriction and structural support to safety-related components (valves, piping, tubing, and fittings).

2.3.3.17.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.17 and UFSAR Section 8.3.1.1.2 to determine whether there is reasonable assurance that the DSDG components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The staff's review of the applicant's scoping results did not identify the omission of any components needed to support the performance of the DSDGs intended functions. The staff also found that the applicant adequately identified in LRA Table 2.3-23 those long-lived, passive components of the DSDG considered to be within the scope of license renewal.

2.3.3.17.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the DSDG that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the DSDG that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.18 Emergency Operations Facility/Technical Support Center (EOF/TSC) Security Diesel Generator

2.3.3.18.1 Summary of Technical Information in the Application

The applicant describes the Emergency Operations Facility/Technical Support Center (EOF/TSC) security diesel generator in LRA Section 2.3.3.18 and provides a list of components subject to an AMR in LRA Table 2.3-24.

The EOF/TSC security diesel generator provides backup electrical power to the EOF/TSC building and security systems upon loss of the normal power supplies.

In LRA table 2.3-24, the applicant identified the following components from the EOF/TFC security diesel generator as being within the scope of license renewal and subject to an AMR (1) ductwork and fittings, (2) intake filters, (3) exhaust silencer, (4) jacket water immersion heater, (5) radiator, and (6) valves, piping, tubing and fittings.

The applicant stated that the intended function common to all components listed above, with the exception of the intake filters, is to provide pressure-retaining boundary so that sufficient flow at adequate pressure is delivered. Other intended functions of components are, as stated, to provide filtration (intake filter) and heat transfer (radiator).

2.3.3.18.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.18 to determine whether there is reasonable assurance that the EOF/TSC security diesel generator components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The staff's review of the applicant's scoping results did not identify the omission of any components needed to support the performance of the EOF/TSC security diesel generator's intended functions. The staff also found that the applicant adequately identified in LRA Table 2.3-24 those long-lived, passive components of the EOF/TSC security diesel generator system considered to be within the scope of license renewal.

2.3.3.18.3 Conclusions

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the EOF/TSC security diesel generator that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the EOF/TSC security diesel generator that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.19 Fuel Oil System

2.3.3.19.1 Summary of Technical Information in the Application

The applicant describes the fuel oil system (FOS) in LRA Section 2.3.3.19 and provides a list of components subject to an AMR in LRA Table 2.3-25.

The FOS supplies fuel oil to the emergency diesel engines, the dedicated shutdown diesel engine, and the diesel engine-driven fire pump from fuel oil storage tanks on site. The fuel oil system also provides fuel oil to the EOF/TSC security diesel generator.

In LRA Table 2.3-25, the applicant identified the FOS components/commodities requiring aging management review (AMR), their intended functions, and provided a reference to the results of the AMR for each component/commodity type.

In the referred table, the applicant identified the following components from the FOS as being within the scope of license renewal and subject to an AMR (1) diesel generator fire pump fuel oil tank and oil storage tank vent filter, (2) dedicated shutdown diesel generator fuel oil day tank, fuel oil priming pump, fuel oil pumps, and fuel oil tank, (3) emergency diesel generator day tank vent filters, fuel oil day tanks, fuel oil duplex filters, fuel oil priming pumps, fuel oil storage tank,

(4) EOF/TSC security diesel generator fuel oil day tank, fuel oil pump, main storage tank, (5) flow orifices/elements, (6) fuel oil transfer pumps, (7) turbine tanks, and (8) valves, piping, tubing, and fittings.

2.3.3.19.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.19 to determine whether there is reasonable assurance that the FOS components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The staff's review of the applicant's scoping results did not identify the omission of any components needed to support the performance of the FOS's intended functions. The staff also found that the applicant adequately identified in LRA Table 2.3-25 those long-lived, passive components of the DGS considered to be within the scope of license renewal.

2.3.3.19.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the FOS that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the FOS that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4 Steam and Power Conversion Systems

2.3.4.1 Turbine System

2.3.4.1.1 Summary of Technical Information in the Application

The applicant describes the turbine system in LRA Section 2.3.4.1.

The turbine system converts the thermal energy of the steam from the main steam system into mechanical energy used to drive the main generator and produce the plant's electrical output. Turbine system valves provide overspeed trip of the turbine to prevent generation of turbine blade missiles. The turbine system is described in RNP UFSAR Section 10.2.2. The evaluation boundaries for the applicable portions of the turbine system were defined on the basis of plant documentation that presents a listing of components within the evaluation boundary of the system.

The turbine system was conservatively included in the scope of license renewal because it contains SCs that are not safety related whose failure may prevent satisfactory accomplishment of safety-related functions and SCs that are relied on during postulated ATWS events. These functions are accomplished by providing protection from turbine overspeed or maintaining the integrity of the low-pressure turbine rotor. However, a review of the turbine system design and component functions during the mechanical system screening process concluded that either (1) the system functions are performed by active components, or (2) any failure of component pressure boundary would not prevent the performance of the system intended functions. This conclusion is consistent with the information presented in the NRC Standard Review Plan for License Renewal, Table 2.1-5 for turbine controls that provide overspeed protection. The screening review concluded that the turbine system components do not perform any intended functions for license renewal; therefore, none of the turbine system components are subject to an AMR.

2.3.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.1 and UFSAR Section 10.2 to determine whether there is reasonable assurance that the turbine system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted. The staff identified no omissions.

The staff evaluated the information provided in LRA Section 2.3.4.1 and UFSAR Section 10.2. The intended functions of the turbine system are accomplished by isolating the steam supply to the turbine under certain conditions and maintaining the integrity of the turbine rotors. The steam isolation valves and turbine rotors are active components excluded from an AMR pursuant to 10 CFR 54.21(a)(1). Failure of the passive, pressure-retaining boundary of the steam isolation valve bodies, turbine steam piping, and the turbine casing would not prevent the accomplishment of the intended functions of the turbine system. Therefore, components of the turbine system are not required by 10 CFR 54.21(a)(1) to be subject to an AMR.

2.3.4.1.3 Conclusions

The staff reviewed the LRA and UFSAR to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the turbine system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has an adequate basis for concluding that no components of the turbine system are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.2 Electro-Hydraulic Control System

2.3.4.2.1 Summary of Technical Information in the Application

The applicant describes the electro-hydraulic control (EHC) system in LRA Section 2.3.4.2.

The EHC system controls the flow of steam to the turbine system through all phases of turbine operation. The system also provides overspeed trip of the turbine to prevent generation of turbine blade missiles. The EHC system is described in RNP UFSAR Section 10.2.2. The evaluation boundaries for the applicable portions of the EHC system were defined on the basis of plant documentation that presents a listing of components within the evaluation boundary of the system. The EHC system was conservatively included in the scope of license renewal, because it contains SCs which are not safety related whose failure may prevent satisfactory accomplishment of safety-related functions. However, a review of the EHC system design and component functions during the mechanical system screening process concludes that (1) the system function is performed by active components, and (2) any failure of component pressure boundary would not prevent the performance of the system intended function. This conclusion is consistent with the information presented in the NRC SRP-LR, Table 2.1-5 for turbine overspeed trip components. The screening review concluded that the EHC system components do not perform any intended functions for license renewal; therefore, none of the EHC system components are subject to an AMR.

2.3.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2 and UFSAR Section 10.2 to determine whether there is reasonable assurance that the EHC system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted. The staff identified no omissions.

The staff evaluated the information provided in LRA Section 2.3.4.2 and UFSAR Section 10.2. The intended functions of the electro-hydraulic control system are accomplished by isolating the steam supply to the turbine under certain conditions. The electro-hydraulic control system valves are active components that perform this function by releasing electro-hydraulic control system fluid pressure. Therefore, components of the electro-hydraulic control system are not required by 10 CFR 54.21(a)(1) to be subject to an AMR.

2.3.4.2.3 Conclusions

The staff reviewed the LRA and UFSAR to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the electro-hydraulic control system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has an adequate basis for concluding that no components of the EHC system are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.3 Turbine Generator Lube Oil System

2.3.4.3.1 Summary of Technical Information in the Application

The applicant describes the turbine generator lube oil system in LRA Section 2.3.4.3.

The turbine generator lube oil system provides oil for cooling and lubricating the turbine bearings and turning gear. The system also provides pressurized oil to the turbine system overspeed and protective trip devices. The turbine generator lube oil system is described in RNP UFSAR Section 10.2.2. The evaluation boundaries for the applicable portions of the turbine generator lube oil system were defined on the basis of plant documentation that presents a listing of components within the evaluation boundary of the system. The turbine generator lube oil system was conservatively included in the scope of license renewal, because it contains SCs that are not safety related whose failure may prevent satisfactory accomplishment of safety-related functions. However, a review of the turbine generator lube oil system design and component functions during the mechanical system screening process concludes that (1) the system function is performed by active components, and (2) any failure of component pressure boundary would not prevent the performance of the system intended function. This conclusion is consistent with the information presented in the NRC SRP-LR, Table 2.1-5 for turbine controls. Therefore, none of the turbine generator lube oil system components is subject to an AMR.

2.3.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.3 and UFSAR Section 10.2 to determine whether there is reasonable assurance that the turbine generator lube oil system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as subject to an AMR to determine if any components were omitted. The staff identified no omissions.

The staff evaluated the information provided in LRA Section 2.3.4.3 and USAR Section 10.2. The turbine generator lube oil system performs no intended function as defined in 10 CFR 54.4(b). Therefore, components of the turbine generator lube oil system are not required by 10 CFR 54.21(a)(1) to be subject to an AMR.

2.3.4.3.3 Conclusions

The staff reviewed the LRA and UFSAR to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the turbine generator lube oil system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has an adequate basis for concluding that no components of the turbine generator lube oil system are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.4 Extraction Steam System

2.3.4.4.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.4, the applicant describes the extraction steam system (ESS). The ESS provides reheating and moisture removal for the steam flow from the high-pressure turbine before it is supplied to the low-pressure turbines. The ESS also provides turbine overspeed protection by utilizing valves to stop the flow of reheat steam to the low-pressure turbine.

The applicant stated that the ESS was included in the scope of license renewal, because it was identified as having SCs that are not safety related whose failure could prevent satisfactory accomplishment of the safety-related functions. The ESS license renewal evaluation boundaries are shown on the piping and instrumentation (P&I) diagram, "Main & Extraction Steam System Flow Diagram," G-190196LR, sheet 1. However, the applicant did not provide a table to list the ESS components subject to an AMR. The ESS is also described in UFSAR Section 10.3, "Main Steam Supply System."

2.3.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.4, UFSAR Section 10.3, and the P&I diagram to determine whether there is reasonable assurance that the ESS components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

In LRA Section 2.3.4.4, the applicant stated that following screening of the ESS, it concluded that none of the ESS components perform an intended function without moving parts or without a change in configuration. Therefore, none of the components in the ESS license renewal evaluation boundaries is subject to an AMR. During its review of the LRA Section 2.3.4.4, the staff concluded that ESS components, such as piping, valves, etc., were long-lived components with a passive function and should be subject to an AMR. Therefore, the staff determined that additional information was needed to complete its review of the ESS.

By letter dated February 11, 2003, the staff requested (via RAIs 2.3.4.4-1, 2.3.4.4-2, 2.3.4.4-3, and 2.3.4.4-4) the applicant to provide the following information:

- justification for not including in an AMR those extraction steam system valves utilized to provide turbine overspeed protection

- highlighting of the extraction steam system license renewal evaluation boundaries in the P&I diagram to ensure that all the long-lived components with a passive function are identified and included for an AMR

- provision of a component/commodity groups table to identify the system components, such as piping, valves, etc., and their intended functions—If a component is not subject to an AMR, detailed justifications for its exclusion

In its response dated April 28, 2003, the applicant stated that two specific features in the ESS are credited with turbine overspeed protection. These are (1) nonreturn air-operated swing check valves located in the extraction steam lines for all but the No. 1 and No. 2 feedwater heaters, and (2) emergency dump valves on these heaters which are not equipped with non return valves. The operation of the check valves is an active function. Failure of the valve or piping pressure boundary would not result in a liability for turbine overspeed, as the diverted steam would still be prevented from returning to the turbine where it might cause overspeed. Similarly, operation of the emergency dump valves is an active function, and should the pressure boundary associated with the dump valves or piping, the result would be to divert steam away from the turbine. In either case, passive failure of the system components would not prevent successful accomplishment of the system intended function. The staff agrees with the applicant that operation of the above-cited valves in the ESS is an active function, and that failure of the system components would not prevent successful accomplishment of the system intended function. Therefore, the staff finds the applicant's rationale for excluding these valves from an AMR acceptable.

In its April 28, 2003, response, the applicant stated that following screening of the ESS, it concluded that none of the system components perform an intended function without moving parts or without a change in configuration. Therefore, none of the components in the ESS boundaries is subject to an AMR. The staff finds acceptable the applicant's clarification of its rationale for finding none of the components in the ESS boundaries subject to an AMR.

Also, in its April 28, 2003, response, the applicant agreed that the ESS provides a system intended function to prevent backflow from feedwater heaters and associated piping. As discussed above, the operation of the check and emergency dump valves in the ESS is an active function, and a loss of component pressure boundary would not prevent successful accomplishment of the system intended function. Therefore, the ESS components are not subject to an AMR. The staff finds the applicant's justification for not listing ESS components in an AMR table acceptable.

In addition, in LRA Section 2.3.4.4, the applicant stated that the ESS was included in the scope of license renewal. Also, in Item 6 of LRA Table 3.4-1, the applicant, in part, stated that the turbine system and ESS are not in the scope of license renewal. The staff requested the applicant to clarify this discrepancy.

In its April 28, 2003, response, the applicant stated that Item 6 of LRA Table 3.4-1 was intended to state that there are no components in the license renewal evaluation boundaries of the ESS that perform an LR intended function. The staff finds the applicant's clarification of the above-cited discrepancy acceptable.

2.3.4.4.3 Conclusions

The staff reviewed the LRA, UFSAR, and the accompanying scoping boundary P&I diagram to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the ESS that are within the scope of license renewal, as required by 10 CFR 54.4(a). Also, the staff concurs with the applicant that no components in the ESS are subject to an AMR as required by 10 CFR 54.21(a)(1).

2.3.4.5 Main Steam System

2.3.4.5.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.5, "Main Steam System," the applicant describes the main steam system (MSS). The MSS transports saturated steam from the SGs to the main turbine and other secondary steam system components. The system is the principal heat sink for the RCS, and protects the RCS and the SGs from overpressurization. The MSS provides isolation of the SGs following a postulated accident, such as a steam line break, and provides steam supply to the steam-driven AFW pump. The MSS license renewal evaluation boundaries are highlighted on the P&I diagram G-190196LR, sheet 1. MSS components subject to an AMR are listed in LRA Table 2.3-26. The MSS is also described in UFSAR Section 10.3, "Main Steam System."

2.3.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.5, UFSAR Section 10.3, and the P&I diagram to determine whether there is reasonable assurance that the MSS components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted. The staff found that the components of the MSS that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.4.5.3 Conclusions

The staff reviewed the LRA, UFSAR, and the accompanying scoping boundary P&I diagram to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the MSS that are within the scope of license renewal, as required by 10 CFR 54.4(a). Also, the staff concludes that the applicant has appropriately identified the MSS components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.6 Steam Generator Blowdown System

2.3.4.6.1 Summary of Technical Information in the Application

In LRA Section 2.3.4.6, "Steam Generator Blowdown System," the applicant describes the steam generator blowdown system (SGBS). The SGBS assists in maintaining required SG chemistry by providing a means for removal of foreign matter that concentrates in the SGs. The system is fed by three independent blowdown lines (one per SG) that penetrate containment and tie to a common blowdown drain tank. The SGBS license renewal evaluation boundaries are highlighted on the P&I diagram G-190243LR, sheet 1. SGBS components subject to an AMR are listed in LRA Table 2.3-27. The SGBS is also described in UFSAR Section 10.4.7, "Steam Generator Blowdown System."

2.3.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.6, UFSAR Section 10.4.7, and the P&I drawing to determine whether there is reasonable assurance that the SGBS components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted. The staff found that the components of the SGBS that have an intended function meeting the criteria of 10 CFR 54.4(a) have been identified as being within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff did not identify any omissions.

2.3.4.6.3 Conclusions

The staff reviewed the LRA, UFSAR, and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the SGBS that are within the scope of license renewal as required by 10 CFR 54.4(a). Also, the staff concludes that the applicant has adequately identified the SGBS components that are subject to AMR as required by 10 CFR 54.21(a)(1).

2.3.4.7 Steam Cycle Sampling

2.3.4.7.1 Summary of Technical Information in the Application

In RNP LRA Section 2.3.4.7, "Steam Cycle Sampling System," the applicant describes the steam cycle sampling system (SCSS). The SCSS provides for sampling and analysis of SG liquid via sample lines connected to the SGBS. A separate sample line is provided for each SG blowdown line.

The applicant stated that the SCSS is in the scope of license renewal, because it contains SCs that are safety related and are relied upon to remain functional during and following design-basis events. The SCSS license renewal evaluation boundaries are highlighted on the P&I diagram "Secondary Sampling System Flow Diagram," HBR2-09006LR, sheet 2. However, the applicant did not provide a table to list the SCSS components subject to an AMR.

2.3.4.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.7, UFSAR Section 10.4.7, and the P&I diagram to determine whether there is reasonable assurance that the SCSS components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

During its review of LRA Section 2.3.4.7, the staff determined that additional information was needed to complete its review of the SCSS. In the February 11, 2003, letter, the staff requested (via RAI 2.3.4.7-1) the applicant to provide a component/commodity groups table to identify the SCSS components and their intended functions. If an SCSS component is not subject to an AMR, the applicant should provide detailed justifications for its exclusion.

In its April 28, 2003, response, the applicant stated that the only components with an intended function in the SCSS are sample heat exchangers. However, the license renewal functional boundary associated with the sample heat exchangers is the CCW system pressure boundary. The CCW system water flows through the shell and around the tubes of the SCSS heat exchangers and provides cooling for the sample flow. The tubing and shells of these heat exchangers are included in LRA Table 2.3-9 for the CCW system. The staff finds acceptable the applicant's rationale for including the tubing and shells of these heat exchangers in LRA Table 2.3-9 for the CCW system.

2.3.4.7.3 Conclusions

The staff reviewed the LRA, UFSAR, and the accompanying scoping boundary drawing to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the SCSS that are within the scope of license renewal, as required by 10 CFR 54.4(a). Also, the staff concludes that the applicant has adequately identified the SCSS components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.8 Feedwater System

2.3.4.8.1 Summary of Technical Information in the Application

The applicant describes the feedwater system in LRA Section 2.3.4.8 and provides a list of components subject to an AMR in LRA Table 2.3-28.

The feedwater system provides preheated, high-pressure feedwater to the SGs under operating conditions. The system provides for feedwater and blowdown isolation following a postulated loss of coolant accident or steam line break event and assists in maintaining SG water chemistry. SG level is controlled to ensure proper water inventory for various operational and accident conditions. The control is achieved by variations in the feedwater flowrate. The feedwater system is described in RNP UFSAR Section 10.4.6.

In LRA Table 2.3-28, the applicant identified eight component/commodity groups of the feedwater system as being within the scope of license renewal and subject to an AMR:

(1) closure bolting
(2) feedwater heat exchanger cover/tubesheet
(3) feedwater heat exchanger cover
(4) feedwater heat exchanger tubesheet
(5) feedwater heat exchanger tubing
(6) flow orifices/elements
(7) temperature elements
(8) valves, piping, tubing, and fittings

The applicant further stated that each of these eight component/commodity groups provides a pressure-boundary intended function. Additionally, the flow orifices/elements were identified as providing the function of flow restriction function, and valves, piping, tubing, and fittings were identified as providing the function of structural support.

2.3.4.8.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.8 and UFSAR Section 10.4.6 to determine whether there is reasonable assurance that the feedwater system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted. The staff's review of the applicant's scoping results did not identify the omission of any components needed to support the performance of the feedwater system's stated intended functions. The applicant adequately identified in LRA Table 2.3-28 those long-lived, passive components of the feedwater system considered to be within the scope of license renewal.

2.3.4.8.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the feedwater system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the feedwater system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.9 Auxiliary Feedwater System

2.3.4.9.1 Summary of Technical Information in the Application

The applicant describes the AFW system in LRA Section 2.3.4.9 and provides a list of components subject to an AMR in LRA Table 2.3-29.

The AFW system supplies feedwater to the SGs when normal feedwater sources are not available. The system provides for isolation of flow to a faulted SG following postulated accidents, such as an SG tube rupture or main steam line break. The AFW system can provide feedwater to any combination of SGs from any one or combination of three pumps; two are motor driven, and the third is steam driven. Steam can be supplied to the steam-driven pump from any of the SGs. The pumps can take suction from the CST, which is the normal source, or from the SWS or the deepwell pumps if the CST is not available. The steam-driven pump provides an independent and diversely powered means of providing feedwater to the SGs.

The steam-driven system provides the required flow through injection lines that are separate from the motor-driven subsystem. The AFW system is described in RNP UFSAR Section 10.4.8.

In LRA Table 2.3-29, the applicant identified 10 component/commodity groups of the AFW system as being within the scope of license renewal and subject to an AMR.

(1) closure bolting

(2) flow orifices/elements

(3) steam- and motor-driven auxiliary feedwater pump lube oil heat exchanger tubing

(4) steam- and motor-driven auxiliary feedwater pump lube oil heat exchanger waterboxes

(5) steam- and motor-driven auxiliary feedwater pump lube oil heat exchanger tubing and shells

(6) steam- and motor-driven auxiliary feedwater pump lube oil heat exchanger shells

(7) steam-driven auxiliary feedwater pump lube oil pump

(8) steam- and motor-driven auxiliary feedwater pumps

(9) steam-driven auxiliary feedwater turbine

(10) valves, piping, tubing, and fittings

The applicant further stated that each of these 10 component/commodity groups provides a pressure-boundary intended function. Additionally, the flow orifices/elements were identified as providing a flow restriction function, the heat exchanger tubing and shells were identified as providing a heat transfer function, and valves, piping, tubing, and fittings were identified as providing the intended function of structural support.

2.3.4.9.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.9 and UFSAR Section 10.4.8 to determine whether there is reasonable assurance that the AFW system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Generally, the staff's review of the applicant's scoping and screening results found that the results were in accordance with 10 CFR 54.4 and 10 CFR 54.21. However, the staff's review of the applicant's scoping results identified a set of components that appeared to support the performance of the AFW system's intended function that were not identified as being within the scope of license renewal. Also, the staff's review of the applicant's screening results questioned aspects of a long-lived, passive component of the AFW system that meet the scoping criteria of 10 CFR 54.4 but which did not appear to be fully addressed in LRA Table 2.3-29. On February 11, 2003, the NRC staff issued RAIs to the applicant to determine whether the applicant had properly applied the scoping criteria of 10 CFR 54.4 and the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs and the applicant's responses, dated April 28, 2003, are described below.

In RAI 2.3.4.9-1, the staff questioned why the alternate source to the AFW system was not within the scope of license renewal. RNP LRA, drawing G-190202-LR, sheet 3, depicts the supply from the deepwell pumps to the AFW pumps as not within the scope of license renewal. As noted in UFSAR Section 10.4.8, this is the source of water credited in the event of a failure of the Lake Robinson Dam. Additionally, the UFSAR notes that makeup from these pumps is required after 2 hours at hot shutdown, assuming the minimum volume of water in the CST. The applicant responded by referring to the RNP response to RAI 2.3.3.8-1. Because the identical issue was raised by RAI 2.3.3.8-1, this question, which is an Open Item, is addressed in Section 2.3.3.8.

In RAI 2.3.4.9-2, the staff questioned whether a restricting orifice, which appears to be the cavitating venturi in the steam turbine AFW pump discharge pipe described in UFSAR Section 10.4.8.2, was specifically addressed, and whether there is any unique AMR associated with such a passive device. This venturi limits flow in the event of low steam generator pressure in the event of a failed discharge flow control valve. The AMR tables do not clearly describe this venturi.

The applicant responded that this cavitating venturi is constructed of both carbon steel and stainless steel (for high-wear parts). This component applies to LRA Table 3.4-1, Item 2, and LRA Table 3.4-2, Items 1, 2, 11, and 13. This component was specifically evaluated in the AMR for the AFW system. Intended functions for this component include pressure boundary and flow restriction. Therefore, this component was evaluated for aging effects on the carbon steel pressure-retaining subcomponents and for aging effects on the wear-resistant (flow-restricting) stainless steel components. As stated in UFSAR Section 10.4.8.2, the function of this cavitating venturi is to limit flow to a low-pressure (i.e., failed) SG in the case of a failed discharge flow control valve. Manual operation of the AFW system limits the flow through the discharge piping to 500 gpm. System flow testing is also limited to approximately 500 gpm. The flow at which this venturi cavitates is approximately 625 gpm. Therefore, in order for this venturi to operate in its flow-limiting mode, there would have to be an event resulting in low SG pressure and a failed discharge flow control valve. Any degradation resulting from this type of operation would be considered event driven and would therefore not be subject to aging management. The staff considered that the applicant adequately addressed AMR for the cavitating venturi and justified its position that no unique AMR is required for potential degradation in a cavitating mode.

2.3.4.9.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the AFW system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the AFW system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.10 Condensate System

2.3.4.10.1 Summary of Technical Information in the Application

The applicant describes the condensate system in LRA Section 2.3.4.10 and provides a list of components subject to an AMR in LRA Table 2.3-30.

The condensate system provides makeup grade water to the steam generators for removing decay and sensible heat from the RCS. The condensate system provides a passive flow of water, by gravity, to the AFW system to support safe shutdown of the plant. The condensate system consists of a CST with piping to the suctions of all three AFW system pumps. The condensate system is described in UFSAR Section 9.2.5.

In LRA Table 2.3-30, the applicant identified three component/commodity groups of the condensate system as being within the scope of license renewal and subject to an AMR.

(1) condensate storage tank
(2) flow orifices/elements
(3) valves, piping, tubing, and fittings

The applicant further stated that each of these three component/commodity groups provides a pressure-boundary intended function. Additionally, the CST provides structural and/or functional support to non-safety-related equipment where failure of this equipment could impact safety-related functions. Valves, piping, tubing, and fittings were also identified as providing the intended function of structural support.

2.3.4.10.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.10 and UFSAR Section 9.2.5 to determine whether there is reasonable assurance that the condensate system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted. Generally, the staff's review of the applicant's scoping and screening results found that the results were in accordance with 10 CFR 54.4 and 10 CFR 54.21. However, the staff's review of the applicant's scoping results identified several components that appeared to support the performance of the condensate system's intended function that were not identified as being within the scope of license renewal. Also, the staff's review of the applicant's screening results questioned aspects regarding passive components of the condensate system that meet the scoping criteria of 10 CFR 54.4 which did not appear to be fully addressed in LRA Table 2.3-30.

On February 11, 2003, the NRC staff issued RAIs to the applicant to determine whether the applicant had properly applied the scoping criteria of 10 CFR 54.4 and the screening criteria of 10 CFR 54.21(a)(1). The staff's RAIs and the applicant's responses, dated April 28, 2003, are described below.

In RAI 2.3.4.10-1, the staff questioned why LRA drawing G-190197-LR, sheet 1, did not identify the 6-inch vent pipe on the top of the CST as within the scope of license renewal. This pipe appears to provide vacuum protection for this tank. The RNP response, dated April 28, 2003, stated that the condensate system is in scope, and the tank is part of the condensate system. The 6-inch vent pipe on top of the CST is an integral part of the condensate storage tank, within the evaluation boundary, and should have been highlighted as part of the boundary of the tank. The vent pipe, as part of the condensate storage tank listed in LRA Table 2.3-30, is covered in LRA Table 3.4-2, Item 13. This response is acceptable as the applicant has confirmed that the vent pipe is within the scope of license renewal.

In RAI 2.3.4.10-2, the staff noted that in LRA drawing G-190197-LR, sheet 1, the class breaks for a number of the pipes connected to the CST appear to be directly at the tank itself, and some pipes have such a break located immediately downstream of the first valve away from the tank. The license renewal boundary highlighting conforms with these class breaks. The staff requested an explanation for the basis for some piping being within scope of license renewal up to the first valve and some terminating at the tank, given the tank's intended pressure boundary function. The applicant's response stated that the pipes highlighted to the first isolation valve are below the minimum water level required to support the system intended functions. The pipes not highlighted are above this minimum water level and are not needed to support the system intended functions. The response further noted that piping within the evaluation boundary for Criterion 2 is not highlighted on any licensing renewal drawing. The Criterion 2 system intended function is to "provide a pressure-retaining boundary to prevent spatial interactions with safety-related equipment." The response clarified a potential misstatement in RAI 2.3.4.10-2 in that the nonhighlighted piping may still be within scope of license renewal if it is required to satisfy Criterion 2 to prevent spatial interactions with safety-related equipment. The staff considers the applicant's response acceptable as it clarified that the piping connecting below the minimum water level is within the scope of license renewal, at least up to the first valve, in order to provide pressure boundary up to that level for the system intended function.

In RAI 2.3.4.10-3, the staff questioned why a diaphragm within the CST, depicted on LRA drawing G-190197-LR, sheet 1, was not listed in Table 2.3-30 as a component requiring an AMR. The applicant's response noted that the Table 2.3-30 entry for the CST contains a reference to AMR Table 3.4-2, Item 5, which addresses the diaphragm within the condensate storage tank. Because the LRA does include the diaphragm within the scope of license renewal and identifies the need for an AMR for this component, this response is acceptable.

2.3.4.10.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any structures, systems, or components that should be within the scope of license renewal were not identified by the applicant. No omissions were found beyond those noted and evaluated as acceptable above. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the condensate system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the condensate system that are subject to an aging management review, as required by 10 CFR 54.21(a)(1).

2.3.4.11 Steam Generator Chemical Addition

2.3.4.11.1 Summary of Technical Information in the Application

The applicant describes the SG chemical addition system in LRA Section 2.3.4.11, and provides a list of components subject to an AMR in LRA Table 2.3-31.

The SG chemical addition system provides for chemical addition to the feedwater system for proper SG chemistry control. Portions of the system provide pressure boundary integrity for the feedwater and AFW systems.

In LRA Table 2.3-31, the applicant identified the valves, piping, tubing, and fittings component/commodity group of the SG chemical addition system as being within the scope of license renewal and subject to an AMR.

The applicant further identified that this component/commodity group provides intended functions of pressure-boundary and structural support.

2.3.4.11.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.11 to determine whether there is reasonable assurance that the SG chemical addition system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The staff's review of the applicant's scoping results did not identify the omission of any components needed to support the performance of the SG chemical addition system's stated intended functions. The applicant adequately identified in LRA Table 2.3-31 those long-lived, passive components of the SG chemical addition system considered to be within the scope of license renewal.

2.3.4.11.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the SG chemical addition system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the SG chemical addition system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.12 Circulating Water System

2.3.4.12.1 Summary of Technical Information in the Application

The applicant describes the circulating water system in LRA Section 2.3.4.12 and provides a list of components subject to an AMR in LRA Table 2.3-32.

The circulating water system provides cooling water from Lake Robinson to the main condensers to condense the steam discharged from the turbine system. Portions of the system provide a flow path for the SWS flow. The circulating water system is described in UFSAR Section 10.4.5.

In LRA Table 2.3-32, the applicant identified the piping and fittings component/commodity group of the circulating water system as within the scope of license renewal and subject to an AMR. The applicant further stated that this component/commodity group provides a pressure-boundary intended function.

2.3.4.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.12 and UFSAR Section 10.4.5 to determine whether there is reasonable assurance that the circulating water system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The staff's review of the applicant's scoping results did not identify the omission of any components needed to support the performance of the circulating water system's stated intended functions. The applicant adequately identified in LRA Table 2.3-32 those long-lived, passive components of the circulating water system considered to be within the scope of license renewal.

2.3.4.12.3 Conclusions

The staff reviewed the LRA and the accompanying scoping boundary drawings to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the circulating water system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the circulating water system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4 Scoping and Screening Results: Structures

This section addresses the scoping and screening results for structures for the LRA for the RNP. The structures consist of containment (2.4.1) and other structures (2.4.2).

Pursuant to 10 CFR 54.21(a)(1), an applicant is required to identify and list SCs subject to an AMR. These are passive, long-lived structures and components that are within the scope of license renewal. To verify that the applicant has properly implemented its methodology, the staff focuses its review on the implementation results. Such a focus allows the staff to confirm that there is no omission of structural components that are subject to an AMR. If the review identifies no omission, the staff has the basis to find that the applicant has identified the structural components that are subject to an AMR.

2.4.1 Containment

The RNP containment structure is a steel-lined concrete shell in the form of a vertical right-circular cylinder with a hemispherical dome and a flat base. The containment encloses the reactor and major components of the RCS and other important systems that interface with the RCS. Also, the containment houses and supports components required for reactor refueling.

This includes the polar crane, refueling cavity, and portions of the fuel handling system. The containment is described in Section 3.8.1 of the RNP UFSAR.

Containment structural components requiring an AMR are identified and discussed in three subsections (1) containment structure, (2) containment internal structural components, and (3) containment external structural components that surround and provide protection for the equipment and personnel hatches.

2.4.1.1 Containment Structure

The LRA identified the components of the containment structure that require an AMR as the concrete dome and cylinder walls, base slab, floor, liner plate, anchors and embedments, penetrations (fuel transfer tube, mechanical penetration assemblies, and electrical penetration assemblies), equipment hatch, personnel hatch, reinforcing steel in concrete, steel pilings, post tensioning system, and containment liner insulation. Each of the components is described below.

The dome and cylinder walls of the containment are supported by the base slab. The base slab is supported by steel pipe piles. The reactor sump (also called the containment sump) is hung from the base slab. A reinforced concrete floor is provided in the containment, above the floor liner, to protect the liner plate from punctures and corrosion that could breach the essentially leak-proof membrane. The interior of the containment is lined with steel plates that are welded together. The liner plate covers the dome, cylinder walls, reactor sump, and the base slab and forms a leak-proof membrane.

Anchor studs are welded to the steel liner and serve to anchor the liner to the concrete containment shell. In penetration areas, penetration steel frames and reinforcing plates are embedded in the concrete containment shell to provide continuity of the reinforcement.

The fuel transfer tube links the refueling canal inside the containment to the spent fuel pool in the FHB. During normal operation, the inside and outside of the fuel transfer tube are dry; a blind flange is installed which serves as part of the containment's essentially leak-tight barrier.

Mechanical penetrations provide the means for passage of process piping and ducts across the containment boundary. With some exceptions, double-barrier piping penetrations are provided. This design consists of a sleeve welded to the liner and connected to the process line by bellows, end plates, or a combination thereof. Connections are provided to pressurize the interior of double-barrier penetrations to assure leak-tight integrity.

Electrical penetrations provide the means for electrical and instrumentation conductors to cross the containment boundary while maintaining an essentially leak-tight barrier. Most electrical penetrations are the cartridge type consisting of a hollow cylinder sealed on both ends and welded to the penetration sleeve. The cartridge is provided with pressurization connections for leak detection.

The equipment hatch is a large flanged penetration that provides access to the containment interior for large equipment. The hatch consists of a bolted, dished door with a double-gasketed flange. The hatch barrel is embedded in the containment wall and is welded to the liner.

The containment personnel hatch (or airlock) consists of a cylindrical steel tube that passes through the concrete wall of the containment and is welded to the liner. It has a bulkhead, with an airlock door, at each end. The doors are interlocked to prevent simultaneous opening. Each of the doors contains double-gasketed seals and local leakage rate testing capability to ensure pressure integrity of the seals.

Reinforcing steel is used in the containment dome, cylinder, and base slab. The reinforcing steel is embedded in concrete, which provides corrosion protection for the steel components. The containment is supported on steel pipe pile foundations. Pilings restrain the containment base slab both vertically and horizontally and safely transmit the structural loads to the dense soils underlying the site.

The posttensioning system consists of vertical tendons located on the centerline of the wall spaced approximately every 3 feet around the periphery of the containment. Tendons made up of high-strength steel bars (six bars per tendon) are placed within 6-inch diameter, heavy wall galvanized steel pipe sheaths. After the tendons were tensioned, the sheaths were filled with Portland cement grout.

The liner on the containment cylinder wall is insulated to limit stresses caused by the high containment temperature following a postulated LOCA. The containment liner insulation extends from the floor up to elevation 367'10" and consists of cross-linked polyvinyl chloride (PVC) foam or polyamide foam panels with an outer sheathing of stainless steel. Various aspects of the containment liner insulation design are described in UFSAR Sections 3.8.1.1.3, 3.8.1.3.1, 3.8.1.4.5, and 3.8.1.6.1.7.

2.4.1.2 Containment Internal Structural Components

The LRA states that the containment internal structural components requiring an AMR are made of concrete and steel materials. The major components are concrete shield walls (primary and secondary), concrete and steel supports (RV, RCP, SG, pressurizer), steel polar crane, ECCS sump screens, and structural and miscellaneous steel. Each of the components is described below.

The primary shield wall is a thick cylindrical wall that encloses the RV and provides biological shielding to permit access into the reactor containment during full power operation for inspection and maintenance. The lower portion of the wall forms an integral part of the main structural support for the RV. The primary shield wall also acts as part of the missile barrier.

The secondary shield wall surrounds the reactor coolant loops and the primary shield wall. It consists of interior walls in the containment structure, the operating floor, and the reactor containment structure.

The RV has three supports located at alternate nozzles. Each support bears on a support shoe, which is fastened to the support structure. The support shoe is a structural member that transmits the support loads to the supporting structure. Each support is designed to restrain vertical, lateral, and rotational movement of the RV, but allows for thermal growth by permitting radial sliding on bearing plates.

Each RCP is supported on a three-legged structural system consisting of three connected columns fabricated of carbon steel members, structural sections, and pipe. Provision for limited movement of the structure in any horizontal direction to accommodate piping expansion is accomplished with a sliding "Lubrite" base plate arrangement and a system of tie rods and anchor bolts which restrains the structure from movement beyond the calculated limits. Sliding shoes at the top of the support structures permit radial thermal growth of the pumps during heatup.

The SGs are supported on a structural system consisting of four connected columns all welded together, fabricated of carbon steel members, with provisions for limited movement of the structure in a horizontal direction to accommodate piping expansion with a system of "Lubrite" plates, hydraulic snubbers, guides, and stops. The "Lubrite" plates, hydraulic snubbers, guides, and stops are designed as damped supports to resist the action of seismic and pipe break loads. The pressurizer is supported on a heavy concrete slab spread between the concrete shield walls. The pressurizer is a bottom skirt support vessel, resting on a ring girder.

The reactor building polar crane is a cantilevered end gantry crane that operates on a circular track supported by the crane wall. The crane and associated rails are seismically qualified Class 1 structures. The polar crane has a main and an auxiliary hoist and provides a means of lifting and handling heavy loads inside the containment. The ECCS sump is located outside the crane wall in the northeast quadrant of the containment. The sump screens are used to stop buoyant materials from entering the ECCS sump.

Structural and miscellaneous steel platforms (grating and checkered plate), stairways, and ladders are provided inside the containment to allow access to the various elevations and areas for inspection and maintenance. Structural and miscellaneous steel platforms also provide support for safety-related and non-safety-related systems and components, including piping, ducts, miscellaneous equipment, electrical cable tray and conduit, instruments and tubing, and electrical and instrumentation enclosures and racks.

2.4.1.3 Containment External Structural Components

The LRA indicates that the containment external structural components requiring an AMR are concrete and steel components around the equipment hatch and the personnel lock shield areas.

The containment external structural components consist of the reinforced concrete structures that surround and provide protection for the equipment and personnel hatches. The structure associated with the equipment hatch also provides protection for the containment purge inlet valves that penetrate the containment wall. The equipment hatch area structure consists of a reinforced concrete slab on grade and reinforced concrete walls that enclose the area around the equipment hatch and containment purge inlet valve.

The personnel lock shield structure consists of a reinforced concrete slab on grade, reinforced concrete walls, and roof slab. The personnel lock shield structure is located in the enclosed area between the reactor containment building, the RAB, and the turbine building.

2.4.1.4 Summary of Technical Information in the Application

The applicant describes the containment structure in LRA Section 2.4.1.1, the containment internal structural components in LRA Section 2.4.1.2, and the containment external structural components in LRA Section 2.4.1.3 and provides a list of components subject to an AMR in LRA Table 2.4-1.

The applicant concluded that the containment is in scope of license renewal because it contains the following:

- SCs that are safety related and are relied upon to remain functional during and following design-basis events
- SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the safety-related functions
- SCs that are relied on during postulated fires, ATWS, and SBO events

Table 2.4-1 lists 51 structural component types requiring an AMR, provides a reference to the results of the AMR for each component type, and identifies the intended functions listed below for the containment structure, the containment internal structural components, and the containment external structural components. The intended functions of the containment structure are as follows:

- provide pressure boundary and/or fission product barrier
- provide rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant
- provide structural and/or functional support to safety-related equipment
- provide structural and/or functional support to non-safety-related equipment where
- failure of this structural component could prevent satisfactory accomplishment of any of the required safety-related functions
- provide structural support and/or shelter to components required for fire protection, ATWS, and/or SBO
- provide spray shield or curbs for directing flow (such as safety injection flow to containment sump)
- provide shelter/protection to safety-related equipment (including radiation shielding)
- serve as missile (internal or external) barrier
- provide heat sink during SBO or design-basis accidents

- provide pressure-retaining boundary so that sufficient flow at adequate pressure is delivered

- provide pipe-whip restraint and/or jet impingement protection

2.4.1.5 Staff Evaluation

The staff reviewed LRA Section 2.4.1 and UFSAR Section 3.8.1 to determine whether there is reasonable assurance that the containment structure, the containment internal structural components, and the containment external structural components within the scope of license renewal and subject to an AMR have been identified in accordance with the requirements of 10 CFR 54.4 and 54.21(a)(1).

In performing the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4-1 lists 51 structural component types that require AMR. These structural component types include anchorage/embedments (exposed surface), anchorage/embedments (embedded/encased), bellows, cable tray and conduit, cavity seal ring plate, concrete sump, containment liner insulation and penetration insulation, containment liner plate (including liner attachments and liner anchors), electrical and instrument panels and enclosures, electrical component supports, electric penetrations, equipment hatch, equipment supports, expansion anchors, external reinforced concrete components (missile shield slab, walls, and roof slabs), fire hose station, floor drains, fuel transfer tube, fuel transfer tube blind flange, grouted tendons, HVAC duct supports, instrument line supports, instrument racks and frames, internal reinforced concrete components (beams, walls, floors, columns, radiation shielding, refueling cavity, equipment pads, missile shields, curbs, hatches, and grout), masonry walls, mechanical penetrations, miscellaneous steel structures (stairs, ladders, platforms, connectors, grating, and checker plate), moisture barrier, NIS detector cover, personnel airlock, pilings, pipe supports, pipe-whip restraints, polar crane, pressurizer and pressurizer surge line supports, protective enclosure (structures sheltering or enclosing plant equipments), reactor cavity (refueling canal) liner plate, RCP supports, reactor manway covers, RV missile shield frame, RV support, reinforced concrete (cylinder wall, dome and basement), seals and gaskets, siding, slide bearing plates, SG supports, structural steel (beams, plates, connectors, and columns), sump screens (supports), threaded fasteners, tube track supports, and vibration isolators.

The applicant states that its determination of structures within the scope of license renewal was made by initially identifying RNP structures and then reviewing them to determine which structures satisfy one or more of the criteria contained in 10 CFR 54.4. The scoping results with respect to whether a structure is in-scope or out of scope are listed in Table 2.2-2, "License Renewal Scoping Results for Structures," which contains 106 structures. In response to RAI 2.5.1-1, the applicant modified the switchyard relay building and switchyard and transformer structures from out of scope to in scope and added isolated phase bus duct yard support structures and 4 kV nonsegregated bus duct yard support in scope to Table 2.2-2. The SCs within the scope are then screened for conformance to the requirements contained in 10 CFR 54.21(a)(1). The SCs that meet the requirements contained in 10 CFR 54.21(a)(1) are identified as requiring an AMR for license renewal.

The applicant states that its methodology for screening SCs includes screening of components and commodities that have been transferred to the civil discipline from the mechanical and electrical disciplines. Evaluation boundaries between mechanical components, electrical components, and structures and structural components were coordinated between discipline reviewers. The types of components and commodities treated in this manner include pipe/component snubbers; fire damper penetration seals; electrical component supports; and electrical cabinets, consoles, cubicles, junction boxes, and panels.

The LRA describes in detail the methodology that the applicant used for scoping and screening structures. The LRA describes in sufficient detail the components of the containment structure, the internal structures, and the containment external structures that are within the scope and subject to an AMR. The staff finds the applicant's methodology for scoping to be acceptable because it meets the criteria contained in 10 CFR 54.4. The staff reviewed Table 2.2-2, "License Renewal Scoping Results for Structures," and found the listed structures acceptable. The staff selected system functions described in the UFSAR to verify that components having intended functions were not omitted from the scope of the Rule. The staff finds the applicant's methodology for screening to be acceptable because it meets the criteria contained in 10 CFR 54.21(a)(1). The staff reviewed the 51 structural components and their intended functions listed in Table 2.4-1 and found them acceptable.

2.4.1.6 Conclusions

The staff reviewed the LRA to determine whether structures or components that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether components that should be subject to an AMR were not identified by the applicant. No omissions were found. The staff concludes that the applicant has adequately identified the structural components of the containment structure, the containment internal structure, and the containment external structure that are within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant has adequately identified the structural components of the containment structure, the containment internal structure, and the containment external structure that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2 Other Structures

Other structures that require license renewal are the passive and long-lived structures other than the containment structure. In LRA Section 2.4.2, "Other Structures," the applicant determined that the following structures are included in the group of other structures for license renewal:

- reactor auxiliary building
- fuel handling building
- turbine building
- dedicated shutdown diesel generator building

- radwaste building
- intake structure
- north service water header enclosure
- Emergency Operations Facility/Technical Support Center security diesel generator building
- discharge structures
- Lake Robinson Dam
- pipe restraint tower
- yard structures and foundations
- refueling system

2.4.2.1 Reactor Auxiliary Building

2.4.2.1.1 Summary of Technical Information in the Application

The applicant describes the RAB in LRA Section 2.4.2.1 and provides a list of components subject to an AMR in LRA Table 2.4-2.

The RAB is a reinforced concrete, seismic Category I structure that houses safety-related systems. It includes the control room, the emergency diesel generator rooms, the RHR pump pit, boron injection tank room, north and south cable vaults, piping penetration area, and the B waste evaporator enclosure installed on the roof of the building. A sump tank room and RHR pit are located below grade.

The RAB reinforced concrete foundation slab of the RAB is supported on pilings (steel pipe, cast-in-place concrete pilings). The auxiliary building is constructed with reinforced concrete bearing walls and floor slabs. Water stops were used in the construction joints of the RAB foundation slab. Also, waterproofing membrane was installed on the building sump and RHR pit exterior surfaces to inhibit the intrusion of ground water. The water stops and waterproofing are considered to be subcomponents of the concrete slabs and walls.

The auxiliary building is described in UFSAR Section 3.8.4.1. In the license renewal evaluation, common walls (and associated penetrations) between the RAB and adjacent buildings were included in the scope of the RAB, with the exception of the containment walls. Also included in the scope of the RAB are stairs and equipment supports located on the exterior walls of the building, and the area between the containment, FHB, and RAB in the vicinity of the RHR pit. Floor drains in the RAB are credited for minimizing flood levels following fire protection system pipe breaks or actuations. The floor drains are in scope for license renewal. The Motor Control Center (MCC) 5 water spray shield is in scope for license renewal, because it protects MCC 5 from water spray following a postulated pipe break.

The auxiliary building is in the scope of license renewal, because it contains (1) SCs that are safety related and are relied upon to remain functional during and following design-basis events, (2) SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the safety-related functions, and (3) SCs that are relied on during postulated fires, ATWS, and SBO events.

Table 2.4.2, lists 40 structural component types requiring an AMR, provides a reference to the results of the AMR for each component type, and identifies the intended functions listed below for the RAB:

- provide pressure boundary and/or fission product barrier
- provide rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant
- provide structural and/or functional support to safety-related equipment
- provide structural and/or functional support to non-safety-related equipment where failure of this structural component could prevent satisfactory accomplishment of any of the required safety-related functions
- provide structural support and/or shelter to components required for fire protection, ATWS, and/or SBO
- provide spray shield or curbs for directing flow (such as safety injection flow to containment sump)
- provide a protective barrier for internal/external flood event
- provide shelter/protection to safety-related equipment (including radiation shielding)
- serve as missile (internal or external) barrier
- provide pipe-whip restraint and/or jet impingement protection

2.4.2.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.1 and UFSAR Section 3.8.4.1 to determine whether there is reasonable assurance that the RAB and structural components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In performing the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4-2 lists 40 structural component types that require AMR. These structural component types include anchorage/embedments (exposed surface), anchorage/embedments (embedded/encased), battery rack, cable tray and conduit, concrete sump, control room ceiling, concrete curb, damper mounting, doors including fire doors, electrical and instrument panels and enclosures, electrical bus duct, electrical component supports, equipment supports, expansion anchors, fire barrier assemblies, fire barrier penetration seals, fire hose station, fire plugs/fire hatches, floor drains, HVAC duct supports, instrument line supports, instrument racks and frames, louvers, masonry walls, miscellaneous steel structures (stairs, ladders, platforms, connectors, grating, and checker plate), pilings, pipe supports, pipe-whip restraints, protective enclosure, raised floor, reinforced concrete (beams, walls, floors, columns, etc.), roof, seismic joint filler, siding, slide bearing plates, spray shields, structural steel (beams, plates, connectors, and columns), threaded fasteners, tube track supports, and vibration isolators.

Since the foundation of the boron injection tank was not listed in Table 2.4-2, on February 11, 2003, the staff requested the applicant in RAI 2.4.2-5 to identify whether the boron injection tank and its foundation were in scope and subject to an AMR. In response to RAI 2.4.2-5, on April 28, 2003, the applicant stated that the boron injection tank and its foundation were in scope and subject to an AMR.

The staff has reviewed the information in LRA Section 2.4.2.1, the UFSAR, and the additional information submitted by the applicant in response to the staff's RAI. The staff finds that the applicant made no omissions in scoping the auxiliary building and structural components for license renewal. The staff's review also found that all the passive SCs identified as being within the scope of license renewal were subject to an AMR.

2.4.2.1.3 Conclusions

The staff reviewed the LRA to determine whether SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the structural components of the auxiliary building that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the structural components of the auxiliary building that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.2 Fuel Handling Building

2.4.2.2.1 Summary of Technical Information in the Application

The applicant describes the FHB in LRA Section 2.4.2.2 and provides a list of components subject to an AMR in LRA Table 2.4-3.

The FHB comprises several adjacent structures and a superstructure that supports the spent fuel cask handling crane. The FHB is further subdivided into structures, rooms, and functional areas.

The FHB includes the spent fuel pit (including the spent fuel pit structure, liner, spent fuel racks, and spent fuel cask storage area), the gas decay tank room, transfer canal structure, new fuel storage room, spent fuel pit cooling pump and heat exchanger rooms, CVCS holdup tank room, hot machine shop, cask and large equipment decontamination area, tool room, and HVAC fan rooms. The FHB is supported on pilings with a higher density of pilings under the spent fuel pit structure, which consists of the gas decay tank room under the spent fuel pit, and the superstructure above the spent fuel pit. Water stops were used in the construction of the FHB sump pits. Water stops are considered to be subcomponents of the concrete sump pit slabs and walls. The spent fuel pit is designed for the underwater storage of spent fuel assemblies after their removal from the reactor. The entire interior basin face and transfer canal are lined with stainless steel plate. A spent fuel pool bridge crane is mounted on rails adjacent to the spent fuel pit and is used to move components within the pit. The superstructure above the spent fuel pit is constructed of structural steel with aluminum or fiberglass siding. The superstructure supports a 125-ton spent fuel cask handling crane that is used to move the spent fuel cask and miscellaneous equipment between ground level and the spent fuel pit.

In the license renewal evaluation, the hot machine shop, tool room, cask and large equipment decontamination area, spent fuel pit heat exchanger room, and the pipe corridor beneath the spent fuel pit pump room were determined to be in scope for license renewal. The spent fuel pit, spent fuel racks, and fuel transfer canal were determined to be in scope. The entire steel and reinforced concrete structure load path (including pilings) supporting the spent fuel cask handling crane are included in scope. The spent fuel cask handling crane itself as well as the spent fuel bridge crane were included in scope. However, the CVCS holdup tank room structure was screened out, because it does not support any intended function of the FHB structure. Civil components and commodities in the new fuel storage room were evaluated and determined not to support any intended function of the FHB structure. The FHB is shown on UFSAR Figures 1.2.2-7 and 1.2.2-8. The spent fuel pit is discussed in UFSAR Section 3.8.4. The FHB is in the scope of license renewal because it contains (1) SCs that are safety related and are relied upon to remain functional during and following design-basis events, (2) SCs that are not safety related whose failure could prevent satisfactory accomplishment of the safety-related functions, and (3) SCs that are relied on during postulated fires and SBO events.

Table 2.4-3 lists 25 structural component types requiring an AMR, provides a reference to the results of the AMR for each component type, and identifies the intended functions listed below for the FHB:.

- provide pressure boundary and/or fission product barrier
- provide structural and/or functional support to safety-related equipment
- provide structural and/or functional support to non-safety-related equipment where failure of this structural component could prevent satisfactory accomplishment of any of the required safety-related functions
- provide structural support and/or shelter to components required for fire protection, an anticipated transient without scam, and/or a station blackout
- provide shelter/protection to safety-related equipment (including radiation shielding)
- provide rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant

- serve as missile (internal or external) barrier
- provide heat sink during station blackout or design-basis accidents

2.4.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.2 and UFSAR Section 3.8.4 to determine whether there is reasonable assurance that the FHB and structural components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In performing the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4-3 lists 25 structural component types that require an AMR. These structural component types include anchorage/embedments (exposed surface), anchorage/embedments (embedded/encased in concrete), bellows, cable tray and conduit, doors, electrical and instrument panels and enclosures, electrical component supports, expansion anchors, fire barrier penetration seals, HVAC duct supports, instrument line supports, instrument racks and frames, masonry walls, miscellaneous steel structures (stairs, ladders, platforms, connectors, grating, and checker plate), pilings, pipe supports, reinforced concrete (beams, walls, floors, columns, etc.), seismic joint filler, spent fuel pool liner, siding, spent fuel bridge crane, spent fuel cask crane, spent fuel storage rack, structural steel (beams, plates, connectors, and columns), and tube track supports.

The staff finds that the applicant made no omissions in scoping the FHB and SCs for license renewal. The staff's review also found that all the passive structures and components identified as being within the scope of license renewal were subject to an AMR.

2.4.2.2.3 Conclusions

The staff reviewed the LRA to determine whether SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the structural components of the FHB that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the structural components of the FHB that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.3 Turbine Building

2.4.2.3.1 Summary of Technical Information in the Application

The applicant describes the turbine building in LRA Section 2.4.2.3 and provides a list of components subject to an AMR in LRA Table 2.4-4.

The turbine building is primarily an open steel frame structure built on reinforced concrete foundations. The foundations are supported on pilings. In general, the turbine building is a Class III structure; Class III structures are not related to reactor operation or safety. However, the turbine building includes a seismic Category I bay in the area that houses and supports the steam-driven AFW pump and associated components. In addition, safety-related piping is routed through a Class III portion of the turbine building in a concrete trench covered with a checkered plate on the bottom floor. The building is located just south of the reactor containment building. The turbine building is described in UFSAR Sections 3.2.1.2 and 3.8.4.

The turbine building is within the scope of license renewal because it contains (1) SCs that are safety related and are relied upon to remain functional during and following design-basis events, (2) SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the safety-related functions, and (3) and SCs that are relied on during postulated fires, ATWS, and SBO events.

Table 2.4-4 lists 26 structural component types requiring an AMR, provides a reference to the results of the AMR for each component type, and identifies the following intended functions for the turbine building:

- provide structural and/or functional support to safety-related equipment.
- provide structural and/or functional support to non-safety-related equipment where failure of this structural component could prevent satisfactory accomplishment of any of the required safety-related functions
- provide structural support and/or shelter to components required for fire protection, ATWS, and/or SBO
- provide spray shield or curbs for directing flow (such as safety injection flow to containment sump)
- serve as missile (internal or external) barrier
- provide shelter/protection to safety-related equipment (including radiation shielding)

2.4.2.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.3 and UFSAR Sections 3.2.1.2 and 3.8.4 to determine whether there is reasonable assurance that the structural components of the turbine building within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In performing the review, the staff selected functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4-4 lists 26 structural component types that require an AMR. These structural component types include anchorage/embedments (exposed surface), anchorage/embedments (embedded/encased), battery rack, cable tray and conduit, doors, electrical and instrument panels and enclosures, electrical bus duct, electrical component supports, equipment supports, expansion anchors, instrument line supports, instrument racks and frames, louvers, masonry walls, miscellaneous steel structures (stairs, ladders, platforms, connectors, grating, and checker plate), pilings, pipe supports, pipe-whip restraints, protective enclosure (structures sheltering or enclosing plant equipment), reinforced concrete (beams, walls, floors, columns, etc.), siding, spray shields, structural steel (beams, plates, connectors, and columns), threaded fasteners, tube track supports, and turbine gantry crane.

Since the safety-related piping is routed through the turbine building in a concrete trench, which was not listed in Table 2.4-2, on February 11, 2003, the staff requested the applicant in RAI 2.4.2-3 to clarify whether the concrete trench is in scope and subject to an AMR. In response to RAI 2.4.2-3, on April 28, 2003, the applicant stated that the concrete trench is in scope and subject to an AMR and is included in the reinforced concrete component in Table 2.4-4.

The staff has reviewed the information in LRA Section 2.4.2.3, the UFSAR, and the additional information submitted by the applicant in response to the staff's RAI. The staff finds that the applicant made no omissions in scoping the turbine building and components for license renewal. The staff's review also found that the passive SCs identified as being within the scope of license renewal were subject to an AMR.

2.4.2.3.3 Conclusions

The staff reviewed the LRA to determine whether structures, systems, or components that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the structural components of the turbine building that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the structural components of the turbine building that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.4 Dedicated Shutdown Diesel Generator Building

2.4.2.4.1 Summary of Technical Information in the Application

The applicant describes the dedicated shutdown diesel generator (DSDG) building in LRA Section 2.4.2.4 and provides a list of components subject to an AMR in LRA Table 2.4-5.

Based on the fire protection safe shutdown analysis, certain postulated fires may cause multiple failures that could prevent safe plant shutdown; therefore, a DS system was installed to bring the plant to a safe shutdown condition. The DSDG is part of the DS system. The DSDG building structure is scoped to include the reinforced concrete slab which supports the DS diesel skid mounted structural steel enclosure, the DS diesel battery charger, and the DS diesel cooling unit. The structure is located west of the turbine building. The DS diesel building is in the scope of license renewal because it contains SCs that are relied on during postulated fires and SBO events.

Table 2.4-5 lists 16 structural component types requiring an AMR, provides a reference to the results of the AMR for each component type, and identifies provisions of structural support and/or shelter to components required for fire protection, ATWS, and/or SBO as the intended function for the DSDG building.

2.4.2.4.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.4 to determine whether there is reasonable assurance that the DSDG building structural components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In performing the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4-5 lists 16 structural component types that require an AMR. These structural component types include the anchor bolt chair for the tank foundation, anchorage/embedments (exposed surface), anchorage/embedments (embedded/encased in concrete), battery rack, cable tray and conduit, electrical and instrument panels and enclosures, electrical component supports, equipment supports, expansion anchors, instrument racks and frames, louvers, pipe supports, protective enclosure (structures sheltering or enclosing plant equipment), reinforced concrete (beams, walls, floors, columns, etc.), structural steel (beams, plates, connectors, and columns), and threaded fasteners.

The staff has reviewed the information in LRA Section 2.4.2.4. The staff finds that the applicant made no omissions in scoping the dedicated shutdown diesel generator building and components for license renewal. The staff's review also found that the passive SCs identified as being within the scope of license renewal were subject to an AMR.

2.4.2.4.3 Conclusions

The staff reviewed the LRA to determine whether SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment during the onsite inspection to determine whether components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the structural components of the DSDG building that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the DSDG building that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.5 Radwaste Building

2.4.2.5.1 Summary of Technical Information in the Application

The applicant describes the radwaste building in LRA Section 2.4.2.5 and provides a list of components subject to an AMR in LRA Table 2.4-6.

The radwaste building is a detached structure located adjacent to the east side of the auxiliary building. The building is used for storage of contaminated materials, such as spent ion exchange resins; filters; anti-C clothing; and contaminated waste materials. An expansion joint assembly is installed at the pipe chase interface between the RAB and the radwaste building to prevent load transfer between buildings. The radwaste building is a reinforced concrete structure supported on a concrete slab. The south and west walls support the grating providing missile and tornado protection for the north service water header enclosure. The radwaste building walls provide protection for the safety-related service water pipe. The radwaste building is in the scope of license renewal because it contains SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the safety-related functions and SCs that are relied on during postulated fires.

Table 2.4-6 lists nine structural component types requiring an AMR, provides a reference to the results of the AMR for each component type, and identifies the following intended functions for the radwaste building:

- provide structural and/or functional support to non-safety-related equipment where failure of this structural component could prevent satisfactory accomplishment of any of the required safety-related functions
- provide structural support and/or shelter to components required for fire protection, ATWS, and/or SBO
- provide shelter/protection to safety-related equipment (including radiation shielding)
- serve as missile (internal or external) barrier

2.4.2.5.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.5 to determine whether there is reasonable assurance that the radwaste building components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In performing the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4-6 lists nine structural component types that require an AMR. These structural component types include anchorage/embedments (exposed surface), anchorage/embedments (embedded/encased), expansion anchors, masonry walls, pipe supports, reinforced concrete (beams, walls, floors, columns, etc.), seismic joint filler (later deleted in response to RAI 2.4.2-7), structural steel (beams, plates, connectors, and columns), and threaded fasteners.

On February 11, 2003, the staff requested the applicant in RAI 2.4.2-7 to clarify whether the components associated with radwaste building cranes and hoists, fire doors, and fire penetrations were in scope and subject to an AMR. In response to RAI 2.4.2-7, on April 28, 2003, the applicant states that the crane and hoists, fire doors, and fire penetrations do not perform a license renewal intended function and were not included in Table 2.4-6. This is because the components' intended functions in the radwaste building are to protect and provide missile shield walls for the safety-related north service water header and to shelter and support a fire water header isolation valve inside a masonry block enclosure at the north end of the radwaste building. Only the components listed in Table 2.4-6 have a license renewal intended function. The response also states that the seismic joint filler should be deleted from Table 2.4-6 because it was inadvertently included. The applicant indicated it will modify the structural steel component's intended function to "provide structural support and/or shelter to components required for fire protection, ATWS and/or SBO," and the reinforced concrete component's intended function to "provide structural and/or functional support to non-safety-related equipment where failure of this structural component could prevent satisfactory accomplishment of any of the required safety-related functions."

The staff has reviewed the information in LRA Section 2.4.2.5 and the applicant's additional submittals. The staff finds that the applicant made no omissions in scoping the radwaste building and structural components for license renewal. The staff's review also found that the passive SCs identified as being within the scope of license renewal were subject to an AMR.

2.4.2.5.3 Conclusions

The staff reviewed the LRA to determine whether SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the radwaste building that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the radwaste building that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.6 Intake Structures

2.4.2.6.1 Summary of Technical Information in the Application

The applicant describes the intake structures in LRA Section 2.4.2.6 and provides a list of components subject to an AMR in LRA Table 2.4-7.

The intake structure is a Class I reinforced concrete structure consisting of three bays. The intake structure supports the four safety-related service water pumps, the three non-safety-related circulating water pumps, and the three firewater pumps (booster pump, motor-driven pump, engine-driven pump). These pumps take suction from the bays and supply water to the plant via their respective systems. There are three traveling screens, one for each bay, to remove small debris from the intake water. The intake structure is in the scope of license renewal because it contains SCs that are safety related and are relied upon to remain functional during and following design-basis events, SCs that are not safety related whose failure could prevent satisfactory accomplishment of the safety-related functions, and SCs that are relied on during postulated fires and SBO events.

Table 2.4-7 lists 16 structural component types requiring an AMR, provides a reference to the results of the AMR for each component type, and identifies the following intended functions for the intake structure:

- provide rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant
- provide structural and/or functional support to safety-related equipment
- provide structural and/or functional support to non-safety-related equipment where failure of this structural component could prevent satisfactory accomplishment of the required safety-related functions
- provide structural support and/or shelter to components required for fire protection, ATWS, and/or SBO
- provide shelter/protection to safety-related equipment (including radiation shielding)
- provide source of cooling water for plant shutdown

2.4.2.6.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.6 to determine whether there is reasonable assurance that the intake structures within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In performing the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4-7 lists 16 structural component types that require an AMR. These structural component types include anchorage/embedments (exposed surface), anchorage/embedments (embedded/encased in concrete), battery rack, cable tray and conduit, concrete fill, electrical and instrument panels and enclosures, electrical component supports, expansion anchors, instrument racks and frames, manhole covers, miscellaneous steel structures (stairs, ladders, platforms, connectors, grating, and checker plate), pipe supports, protective enclosure (structures sheltering or enclosing plant equipment), reinforced concrete (beams, walls, floors, columns, etc.), siding, and structural steel (beams, plates, connectors, and columns).

On February 11, 2003, the staff requested the applicant in RAI 2.4.2-8 to provide justifications for the exclusion of the three traveling screens that remove small debris from the intake water. In response to RAI 2.4.2-8, on April 28, 2003, the applicant provided the following justification:

> The traveling screens are designated as non-safety related in the circulating water system. The traveling screens do not provide a license renewal intended function as defined in 10 CFR 54.4(a)(1), (2) or (3). There is a relatively low flow velocity (approximately 0.07 ft/sec) through the traveling screens during a design basis event and the condition of the RNP impoundment is relatively nonaggressive. Additionally, the following factors were considered during review of the traveling screens for scoping:

- The traveling screens are not required to perform a function during and following a design basis event, and therefore do not meet the scoping criteria of 10 CFR 54.4(a)(1)(i), (ii), or (iii).
- There is no credible failure mode of the traveling screens that could prevent satisfactory accomplishment of any of the functions identified in paragraphs 10 CFR 54.4(a)(1)(i), (ii), or (iii). Therefore the traveling screens do not meet the scoping criteria of 10 CFR 54.4(a)(2).
- The traveling screens are not required to perform a function in support of the regulated events of 10 CFR 54.4(a)(3).

Based on the above, the traveling screens are not considered to meet the scoping criteria of 10 CFR 54.4(a) and do not perform a licensee renewal intended function per 10 CFR 54.4(b).

The staff has reviewed the information in LRA Section 2.4.2.6 and the responses to the staff's RAI. The staff finds that the applicant made no omissions in scoping the intake structure and structural components for license renewal. The staff's review also found that the passive SCs identified as being within the scope of license renewal were subject to an AMR.

2.4.2.6.3 Conclusions

The staff reviewed the LRA to determine whether SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the intake structures that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the intake structures that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.7 North Service Water Header Enclosure

2.4.2.7.1 Summary of Technical Information in the Application

The applicant describes the north service water header enclosure in LRA Section 2.4.2.7 and provides a list of components subject to an AMR in LRA Table 2.4-8.

The north service water header enclosure provides support and protection for a portion of the north service water header that is routed above ground. The north service water header has been designed with protective barriers to ensure that this portion of the SWS is capable of withstanding the passage of a tornado without a loss of function. The protective barriers provided for the aboveground portion of the north service water header are a double layer of grating and a poured concrete wall in the area to the south and west of the radwaste building. The radwaste building's south and west walls also provide missile protection. The concrete structure is designed as Class I. Service water pit 3, south of the radwaste building, is surrounded by and included in the scope of the north service water header enclosure.

The north service water header enclosure is in the scope of license renewal because it contains (1) SCs that are safety related and are relied upon to remain functional during and following design-basis events, (2) SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the safety-related functions, and (3) SCs that are relied on during postulated fires and SBO events.

Table 2.4-8 lists 15 structural component types requiring an AMR, provides a reference to the results of the AMR for each component type, and identifies the following intended functions for the north service water header enclosure:

- provide rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant
- provide structural and/or functional support to safety-related equipment
- provide structural and/or functional support to non-safety-related equipment where failure of this structural component could prevent satisfactory accomplishment of any of the required safety-related functions
- provide structural support and/or shelter to components required for fire protection, ATWS, and/or SBO
- provide spray shield or curbs for directing flow (such as safety injection flow to containment sump)
- provide shelter/protection to safety-related equipment (including radiation shielding)
- serve as missile (internal or external) barrier

2.4.2.7.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.7 to determine whether there is reasonable assurance that the north service water header enclosure components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In performing the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4-8 lists 15 structural component types that require an AMR. These structural component types include anchorage/embedments (exposed surface), anchorage/embedments (embedded/encased in concrete), cable tray and conduit, concrete fill, concrete curb, electrical and instrument panels and enclosures, electrical component supports, expansion anchors, instrument line supports, masonry walls, miscellaneous steel structures (stairs, ladders, platforms, connectors, grating, and checker plate), pipe supports, reinforced concrete (beams, walls, floors, columns, etc.), structural steel (beams, plates, connectors, and columns), and threaded fasteners.

Section 3.2.1.2 of the UFSAR states that the concrete missile shield wall and the support slab for the aboveground portions of the service water system north header are Class I. These two structural components were not specifically listed in LRA Table 2.4-8. On February 11, 2003, the staff requested the applicant to clarify whether they are subject to an AMR. In response to RAI 2.4.2-2, on April 28, 2003, the applicant stated that they are subject to an AMR.

The staff has reviewed the information in LRA Section 2.4.2.7 and the applicant's response to the staff's RAI. The staff finds that the applicant made no omissions in scoping the north service water header enclosure and structural components for license renewal. The staff's review also found that the passive SCs identified as being within the scope of license renewal were subject to an AMR.

2.4.2.7.3 Conclusions

The staff reviewed the LRA to determine whether SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the structural components of the north service water header enclosure that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the north service water header enclosure that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.8 Emergency Operations Facility/Technical Support Center Security Diesel Generator Building

2.4.2.8.1 Summary of Technical Information in the Application

The applicant describes the EOF/TSC security DG building in LRA Section 2.4.2.8 and provides a list of components subject to an AMR in LRA Table 2.4-9.

The EOF/TSC security DG building houses equipment that is relied on to provide electrical power following postulated fires. This structure consists of a reinforced concrete slab with walls constructed of concrete block and removable (from inside the structure) steel grating panels. The building is located west of the main power block near the work control building. The EOF/TSC security DG building is in the scope of license renewal because it contains SCs that are relied on during postulated fires.

Table 2.4-9 lists 16 structural component types requiring an AMR, provides a reference to the results of the AMR for each component type, and identifies the intended function of the EOF/TSC security DG building as the provision of structural support and/or shelter to components required for fire protection, ATWS, and/or SBO.

2.4.2.8.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.8 to determine whether there is reasonable assurance that the EOF/TSC security DG building components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not

omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4-9 lists 16 structural component types that require an AMR. These structural component types include anchorage/embedments (exposed surface), anchorage/embedments (embedded/encased in concrete), battery rack, cable tray and conduit, doors, electrical and instrument panels and enclosures, electrical component supports, expansion anchors, masonry walls, miscellaneous steel structures (stairs, ladders, platforms, connectors, grating, and checker plate), pipe supports, protective enclosure, reinforced concrete (beams, walls, floors, columns, etc.), structural steel (beams, plates, connectors, and columns), threaded fasteners, and vibration isolators.

The staff has reviewed the information in LRA Section 2.4.2.8. The staff finds that the applicant made no omissions in scoping the EOF/TSC security DG building and structural components for license renewal. The staff's review also found that the passive SCs identified as being within the scope of license renewal were subject to an AMR.

2.4.2.8.3 Conclusions

The staff reviewed the LRA to determine whether SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the structural components of the EOF/TSC security DG building that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the EOF/TSC security DG building that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.9 Discharge Structures

2.4.2.9.1 Summary of Technical Information in the Application

The applicant describes the discharge structures in LRA Section 2.4.2.9.

The structures associated with the discharge of circulating water and service water to Lake Robinson are seal well #2, the discharge canal, and the canal outlet structure. Seal well #2 is an underground/underwater reinforced concrete structure which receives water from the underground circulating water discharge conduit and injects the water into the discharge canal. The discharge canal is an earthen structure that directs condenser cooling and service system water discharged from the plant to Lake Robinson via a channel. The discharge canal originates just east of the plant, parallels the west shore of the lake, and terminates in the lake near its upper end. The canal outlet structure is a reinforced concrete structure located at the intersection of the discharge canal and Lake Robinson. It contains a weir over which water is discharged, thereby promoting mixing with water in the lake. In the scoping process, the discharge structures were conservatively assumed to contain SCs that are not safety related but whose failure could prevent satisfactory accomplishment of safety-related functions. However, during screening, it was concluded that none of the structural components of the discharge structures could prevent the performance of any required safety-related function.

Therefore, the discharge structure components perform no intended functions and are not subject to an AMR.

2.4.2.9.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.9 to determine whether there is reasonable assurance that the discharge structures components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In performing the review, the staff selected functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

The staff has reviewed the information in LRA Section 2.4.2.9. The staff finds that the applicant made no omissions in scoping the discharge structures and structural components for license renewal. The staff agrees with the applicant's conclusion that none of the structural components of the discharge structures could prevent the performance of any required safety-related function. Therefore, the discharge structure components perform no intended functions and are not subject to an AMR.

2.4.2.9.3 Conclusions

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the structural components of the discharge structures that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has an adequate basis for concluding that no components of the discharge structures are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.10 Lake Robinson Dam

2.4.2.10.1 Summary of Technical Information in the Application

The applicant describes the Lake Robinson Dam in LRA Section 2.4.2.10 and provides a list of components subject to an AMR in LRA Table 2.4-10. Lake Robinson was constructed originally as a cooling water source for the Robinson Unit 1 fossil station. The lake was created by construction of the Lake Robinson Dam. The dam has a central vertical clay core and supporting shells of compacted sand. The dam has a maximum height of about 50 feet. Riprap protection is provided on the upstream face from the crest to elevation 205 feet (5 ft below low water elevation) and on the downstream side for that portion of the slope below levation 195 feet. The dam includes a reinforced concrete spillway. Two large steel gates and steel valves are used to control water release from the reservoir. The Lake Robinson Reservoir provides plant cooling water for normal and emergency situations and supplies fire protection water.

Lake Robinson Dam is in the scope of license renewal because it contains SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the safety-related functions and SCs that are relied on during postulated fires.

Table 2.4-10 lists seven structural component types requiring an AMR, provides a reference to the results of the AMR for each component type, and identifies the following intended functions for the Lake Robinson Dam:

- provide structural and/or functional support to safety-related equipment
- provide structural and/or functional support to non-safety-related equipment where failure of this structural component could prevent satisfactory accomplishment of any of the required safety-related functions
- provide structural support and/or shelter to components required for fire protection, ATWS, and/or SBO
- provide source of cooling water for plant shutdown

2.4.2.10.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.10 to determine whether there is reasonable assurance that the Lake Robinson Dam components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In performing the review, the staff selected functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4-10 lists seven structural component types that require an AMR. These structural component types include anchorage/embedments (exposed surface), anchorage/embedments (embedded/encased in concrete), lake dam, spillway for dam structure, structural steel (beams, plates, connectors, and columns), gates/valves, and threaded fasteners.

The staff reviewed LRA Section 2.4.2.10 to determine whether there is reasonable assurance that the Lake Robinson Dam components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1). The staff finds that the applicant has properly identified the structural components that are subject to an AMR.

2.4.2.10.3 Conclusions

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the structural components of the Lake Robinson Dam that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the Lake Robinson Dam that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.11 Pipe Restraint Tower

2.4.2.11.1 Summary of Technical Information in the Application

The applicant describes the pipe restraint tower in LRA Section 2.4.2.11 and provides a list of components subject to an AMR in LRA Table 2.4-11. The pipe restraint tower is a seismic Category I structural steel frame structure supported by a reinforced concrete foundation. The foundation is supported on pilings. Grating platforms are located at various elevations. This structure is required for mitigation of pipe whip and jet impingement as a result of postulated HELBs outside the containment. The location is due south of the reactor containment structure approximately between turbine building column lines 11 and 12. The pipe restraint tower supports the main steam safety relief and isolation valves, the feedwater isolation valves, and acts as a pipe-whip restraint for the main steam and feedwater lines. The pipe restraint tower is not physically attached to the containment building and is connected via platforms to the seismic Category I portion of the turbine building.

The pipe restraint tower is in the scope of license renewal because it contains (1) SCs that are safety related and are relied upon to remain functional during and following design-basis events, (2) SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the safety-related functions, and (3) SCs that are relied on during postulated fires, ATWS, and SBO events.

Table 2.4-11 lists 13 structural component types requiring an AMR, provides a reference to the results of the AMR for each component type, and identifies the following intended functions for the pipe restraint tower:

- provide structural and/or functional support to safety-related equipment
- provide structural and/or functional support to non-safety-related equipment where failure of this structural component could prevent satisfactory accomplishment of any of the required safety-related functions
- provide structural support and/or shelter to components required for fire protection, ATWS, and/or SBO
- provide shelter/protection to safety-related equipment (including radiation shielding)
- provide pipe-whip restraint and/or jet impingement protection

2.4.2.11.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.11 to determine whether there is reasonable assurance that the pipe restraint tower components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In performing the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4-11 lists 13 structural component types that require an AMR. These structural component types include anchorage/embedments (exposed surface), anchorage/embedments (embedded/encased in concrete), cable tray and conduit, electrical and instrument panels and enclosures, electrical component supports, instrument line supports, miscellaneous steel structures (stairs, ladders, platforms, connectors, grating, and checker plate), piling, pipe supports, pipe-whip restraints, reinforced concrete (beams, walls, floors, columns, etc.), structural steel (beams, plates, connectors, and columns), and threaded fasteners.

The staff has reviewed the information in LRA Section 2.4.2.11. The staff finds that the applicant made no omissions in scoping the pipe restraint tower and structural components for license renewal. The staff's review also found that all the passive SCs identified as being within the scope of license renewal are subject to an AMR.

2.4.2.11.3 Conclusions

The staff reviewed the LRA to determine whether SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the structural components of the pipe restraint tower that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the pipe restraint tower that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.12 Yard Structures and Foundations

2.4.2.12.1 Summary of Technical Information in the Application

The applicant describes the yard structures and foundations in LRA Section 2.4.2.12 and provides a list of components subject to an AMR in LRA Table 2.4-12. Yard structures and foundations include concrete foundations and steel supports for miscellaneous in-scope equipment, concrete trenches for in-scope piping and utilities, electrical enclosures and panels located in Personnel Access Portal (PAP) West supporting security lighting, and concrete duct banks and manholes. Portions of the PAP West structure were evaluated to be in scope during the screening process for security lighting when security lighting circuits were determined to be located in the yard structures. The yard structures and foundations classification includes miscellaneous yard structures consisting of foundations (concrete and structural steel) for piping, cable trays, conduits, and electrical enclosures and panels located outside other structures and buildings.

Yard structures and foundations are within the scope of license renewal because they contain SCs that are safety related and are relied upon to remain functional during and following design-basis events, SCs that are not safety related but whose failure could prevent satisfactory accomplishment of the safety-related functions, and SCs that are relied on during postulated fires and SBO events. (Individual structures may not perform all of these functions.)

Table 2.4-12 lists 20 structural component types requiring an AMR, provides a reference to the results of the AMR for each component type, and identifies the following intended functions for yard structures and foundations

- provide rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant
- provide structural and/or functional support to safety-related equipment
- provide structural and/or functional support to non-safety-related equipment where failure of this structural component could prevent satisfactory accomplishment of any of the required safety-related functions
- provide structural support and/or shelter to components required for fire protection, ATWS and/or SBO
- provide shelter/protection to safety-related equipment (including radiation shielding)

2.4.2.12.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.12 to determine whether there is reasonable assurance that the yard structures and foundations components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In performing the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Table 2.4-12 lists 20 structural component types that require an AMR. These structural component types include anchor bolt chair for tank foundation, anchorage/embedments (exposed surface), anchorage/embedments (embedded/encased in concrete), cable tray and conduit, concrete tank foundation, doors, electrical and instrument panels and enclosures, electrical component supports, electrical manhole, expansion anchors, manhole covers, masonry walls, miscellaneous steel structures (stairs, ladders, platforms, connectors, grating, and checker plate), pipe supports, protective enclosure, reinforced concrete (beams, walls, floors, columns, etc.), siding, structural steel (beams, plates, connectors, and columns), threaded fasteners, and underground conduit duct bank. On February 11, 2003, the staff requested the applicant in RAI 2.5.1-1 to explain why the screening results in section 2.5.1 did not include offsite power system structures or components. In response to RAI 2.5.1-1, on April 28, 2003, the applicant provided a list supporting structures and civil/structural component/commodity groups which are required for restoration of offsite power. The switchyard relay building, switchyard and transformer structures, isolated phase bus duct yard support structures, and the 4 kV nonsegregated bus duct yard support structures were added as in scope. Electrical bus duct (enclosure), battery rack, and pilings were added to

Table 2.4.12 as structural component types that are in scope and subject to an AMR to meet the requirement of 10 CFR 54.4(a)(3) with respect to the offsite power system SCs.

Since the UFSAR lists the primary water storage tank as a Class I component and Section 2.4.2.12 of the LRA states that the primary water storage tank was determined to be outside of the intended function boundary for license renewal, on February 11, 2003, the staff requested the applicant to provide justifications for that determination. In response to RAI 2.4.2-4, on April 28, 2003, the applicant provided the following justification:

> The original RNP licensing basis considered the CVCS flow path from the boric acid storage tanks to the blender (and including the PWST and its flow path) and to the charging pumps' suction to be safety related, and required operability of this equipment in the technical specifications. Safety-related tanks were designed to Class I criteria. A subsequent license change identified that only the RWST was required as a postaccident makeup source of borated water, and relocated the requirements for the CVCS and PWST to the technical requirements manual. Therefore, the PWST does not support any system intended function, which resulted in the above conclusion stated in LRA Section 2.4.2.12. Section 2.4.2.12 was submitted to the NRC prior to RNP reformulating its position with respect to 10 CFR 54.4(a)(2). Based on recent industry guidance relating to 10 CFR 54.4(a)(2) and piping systems (Criterion 2 piping), the PWST required evaluation for its potential spatial interactions with nearby safety-related equipment. There is no safety-related equipment in its proximity that would be adversely affected by spray or leakage from the tank. Consequently, the PWST was determined to have no potential spatial interaction with safety-related equipment and does not require aging management.

The staff finds the above response reasonable and acceptable.

Table 3.2.1-2 of the UFSAR lists the S/G drain (flash) tank, refueling water storage tank, accumulator tanks, fuel oil storage tank, chemical drain tank, waste holdup tanks, sump tank, gas decay tanks, spent resin storage tank, and RCDT as Class I components. However, none of these tanks is listed in Table 2.2-1, "License Renewal Scoping Results for Mechanical Systems," or Table 2.2-2, "License Renewal Scoping Results for Structures of the LRA." On February 11, 2003, the staff requested the applicant to clarify whether these tanks are within scope and subject to an AMR.

In response to RAI 2.4-1 and RAI 2.4-5, on April 28, 2003, the applicant stated that the S/G drain (flash) tank, refueling water storage tank, accumulator tanks, fuel oil storage tank, and their foundations are in scope and subject to an AMR, but the remaining tanks (namely, the chemical drain tank, waste holdup tanks, sump tank, gas decay tanks, spent resin storage tank, and the RCDT) are mechanical components within the liquid waste processing system and the gaseous waste processing system that do not require an AMR. The liquid waste processing system is within the scope of the LR rule because it is a Criterion 2 piping system, the containment isolation function and the electrical components associated with EQ and Regulatory Guide (RG) 1.97 functions. None of the tanks within the liquid radwaste system support these system intended functions. The gaseous waste processing system has no system function that meets the LR scoping criteria and is not in scope of the rule as explained below. In fact, an evaluation of a complete rupture of a waste gas decay tank has shown that the dose limits as described above would not be exceeded. The waste gas decay tank rupture is considered the worst-case tank rupture of any radwaste tank (liquid or gas) due to the curie content and rapid expansion of the gaseous contents (UFSAR Section 15.7.1.1 and 15.7.2.1). Paragraph 15.7.1.3 of the UFSAR concludes, "an accidental waste gas release would present no hazard to the health and safety of the public." Based on this conclusion, none of the tanks in the gaseous radwaste system requires an AMR because the system is not in scope. The liquid radwaste system is in scope, but the identified tanks do not support any intended system function and on that basis do not require an AMR.

The staff finds the above response reasonable and acceptable.

The staff has reviewed the information in LRA Section 2.4.2.12, the UFSAR, and the additional information submitted by the applicant in response to the staff's RAIs. The staff finds that the applicant made no omissions in scoping the yard structures and foundations and structural components for license renewal. The staff's review also found that the applicant has properly identified all the passive SCs requiring an AMR.

2.4.2.12.3 Conclusions

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the structural components of the yard structures and foundations that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the yard structures and foundations that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2.13 Refueling System

2.4.2.13.1 Summary of Technical Information in the Application

The applicant describes the refueling system in LRA Section 2.4.2.13. The refueling system contains components in the containment and the FHB and provides a safe, effective means of transporting and handling fuel. There are no safety-related components in the refueling system except for the fuel transfer tube and the fuel transfer tube blind flange. The flange was transferred to the containment building and is screened there along with the fuel transfer tube. No safety-related functions are associated with this equipment, and no intended functions were assigned to the system other than for the fuel transfer tube flange. Therefore, all remaining components were screened as out of the evaluation boundary. The flange on the fuel transfer tube is discussed in the LRA as part of the containment.

2.4.2.13.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2.13 to determine whether there is reasonable assurance that the refueling system components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In performing the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Since the fuel transfer tube and the blind flange have been included with the license renewal scope in the containment structure and are subject to an AMR, the staff agrees with the applicant's conclusion to screen out the remaining components of the refueling system since they are not relied upon to remain functional during and following the postulated fire event, SBO event, or design-basis events.

2.4.2.13.3 Conclusions

The staff reviewed the LRA to determine whether SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the structural components of the refueling system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the refueling system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.3 Evaluation Findings

On the basis of this review, the staff concludes that there is reasonable assurance that the applicant has adequately identified the structures and structural components that are within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a), and that the applicant has adequately identified the structural components that are subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

2.5 Scoping and Screening Results: Electrical/Instrumentation and Control Systems

This section addresses the scoping and screening results of electrical/I&C systems at RNP for license renewal. As required by 10 CFR 54.21(a)(1), an applicant must identify and list SCs subject to an AMR. These are passive, long-lived SCs that are within the scope of license renewal. To verify that the applicant has properly implemented its methodology, the staff focuses its review on the implementation results. Such a focus allows the staff to confirm that there is no omission of electrical system components that are subject to an AMR. If the review identifies no omission, the staff has the basis to find that there is reasonable assurance that the applicant has identified the electrical system components that are subject to an AMR.

The applicant performed the screening for electrical/I&C components on a generic component commodity group basis for the in-scope electrical/I&C systems. The in-scope electrical/I&C component commodity groups identified at RNP are listed in Table 2.5.1. The table includes all electrical/I&C components commodity groups, provided in NEI 95-10, Appendix B, with the exception of those types that did not meet the requirements of 10 CFR 54.4(a).

Table 2.5-1 RNP In-Scope Electrical/I&C Components

Alarm Units	Electrical/I&C Penetration Assemblies	Loop Controllers	Signal Conditioners
Analyzers	Elements	Meters	Solenoid Operators
Annunciators	Fuses	Motor Control Centers	Solid-State Devices
Batteries	Generators	Motors	Splices
Bus Duct	Heat Tracing	Power Distribution Panels	Surge Arresters
Chargers	Heaters	Power Supplies	Switches
Circuit Breakers	Indicators	Radiation Monitors	Switchgear
Converters	Insulated Cables and Connections	Recorders	Terminal Blocks
Communication Equipment	Inverters	Regulators	Thermocouples
Electrical Controls and Panel Internal Component Assemblies	Isolators	Relays	Transducers
	Light Bulbs	RTDs	Transformers
	Load Centers	Sensors	

The applicant eliminated the following components because they did not meet the license renewal scoping requirements of 10 CFR 54.4(a):

- electrical bus (the isolated-phase bus system and the switchyard and transformer system)
- transmission conductors
- high-voltage insulators
- high-voltage surge arresters
- uninsulated ground conductors

After applying the screening criteria as discussed in 10 CFR 54.21(a)(1)(i), the applicant determined that the following electrical commodities at RNP require an AMR.

- bus duct (2.5.1)
- insulated cables and connections (2.5.2)
- electrical and I&C penetration assemblies (2.5.3)

2.5.1 Bus Duct

Section 2.5.3.1, "Bus Duct," in the LRA identifies bus ducts as passive long-lived component commodity groups that connect power supplies and load centers in order to deliver voltage and current to support the system's intended function as defined in 10 CFR 54.21(a)(1)(i).

2.5.1.1 Summary of Technical Information in the Application

The applicant describes the bus ducts in LRA Section 2.5.3.1 and provides a list of components subject to an AMR in LRA Table 3.6-2.

The function of bus ducts is to electrically connect power supplies and load centers to deliver voltage and current. The bus ducts utilize preassembled raceway (enclosure) design with internal conductors installed on electrically insulated supports. Bus duct insulated copper conductors, their associated insulators, and electrical connections are reviewed as a single component commodity group. Bus ducts within scope of license renewal are (1) nonsegregated 480-V bus duct connecting EDG A to emergency bus E1, (2) nonsegregated 480-V bus duct connecting EDG B to emergency bus E2, (3) nonsegregated bus duct from the DS system transformer to the DS bus, (4) nonsegregated bus duct connecting 480-V switchgear bus 3 to the DS bus, and (5) the cross-tie, nonsegregated bus duct connecting emergency bus E1 and E2.

Bus ducts are not in the RNP EQ Program. Equipment in the EQ Program has documented qualified life. Components in the EQ Program that have a qualified life less than 40 years are replaced on the basis of a specified time period at the end of their qualified life. Components in the EQ Program that have a qualified life based on the 40-year current operating license term are the subject of time-limited aging analysis (TLAA). Since no bus ducts are within the scope of the EQ Program, bus ducts in the scope of license renewal are considered to meet the criteria of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR.

2.5.1.2 Staff Evaluation

The staff reviewed LRA Section 2.5.3.1 to determine whether there is reasonable assurance that the bus duct components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1). The bus ducts identified by the applicant as requiring AMR are used between EDGs and emergency buses and between DS system transformer to DS bus to 480-V switchgear bus 3 to conduct electrical power (voltage and current). The staff reviewed these component categories against the requirements of 10 CFR 54.4(a)(1) and 10 CFR 5.4.4(a)(3) and found these categories are included in these requirements.

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

2.5.1.3 Conclusions

The staff reviewed the LRA to determine whether any structures, systems, or components that should be within the scope of license renewal were not identified by the applicant. No omissions were found. In addition, the staff performed an independent assessment to determine whether any components that should be subject to an AMR were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the bus duct components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the bus duct components that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.2 Insulated Cables and Connections

Section 2.5.3.2, "Insulated Cables and Connections," in the LRA identifies cables and connections as long-lived and non-EQ component groups that perform an electrical passive function in support of its system intended function as defined by 10 CFR 54.21(a)(1)(i).

2.5.2.1 Summary of Technical Information in the Application

The applicant describes the insulated cables and connections in LRA Section 2.5.3.2 and provides a list of components subject to an AMR in LRA Section 2.5.4.

The function of insulated cables and connections is to electrically connect specified sections of an electrical circuit to deliver voltage, current, or signals. Electrical cables and their required terminations (i.e., connections) are reviewed as a single component commodity group. The types of connections included in this review are splices, connectors, and terminal blocks. Numerous insulated cables and connections are included in the EQ Program. The insulated cables and connections that are included in this program have a qualified life that is documented in the EQ Program. Components in the EQ Program that have a qualified life less than 40 years are replaced on the basis of a specified time period at the end of their qualified life. Components in the EQ Program that have a qualified life based on the 40-year current operating license term are the subject of TLAA. Accordingly, all insulated cables and connections within the EQ Program are exempt from screening under 10 CFR 54.21(a)(1)(ii) and are not subject to an AMR review. The TLAA associated with electrical/I&C components within the EQ Program is discussed in LRA Section 4.4.1.

Insulated cables and connections that perform an intended function within the scope of license renewal, but are not included in the EQ Program, meet the criteria 54.21(a)(1)(ii) and are subject to an AMR.

2.5.2.2 Staff Evaluation

The staff reviewed LRA Section 2.5.3.2 to determine whether there is reasonable assurance that the insulated cable and connections components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 54.21(a)(1).

In the performance of the review the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not

omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

Consistent with the requirements specified in 10 CFR 54.4(a), fuse holders (including fuse clips and fuse blocks) are considered to be passive electrical components. Fuse holders would be scoped, screened, and included in the AMR in the same manner as terminal blocks and other types of electrical connections that are currently being treated in the process. This staff position applies only to fuse holders that are not part of a large assembly. Based on this information, the staff requires that applicable fuse holders be included within the scope of license renewal and subject to an AMR, or additional justification for their exclusion needs to be provided (RAI 2.5.2-1). The staff guidance on the identification and treatment of electrical fuse holders for license renewal is contained in a May 16, 2002, letter to the NEI and the Union of Concerned Scientists.

In response to staff's RAI 2.5.2-1, the applicant, by letter dated April 28, 2003, stated that the fuse holders are passive, long-lived electrical components. The applicant considers them to be another type of electrical connection similar to a terminal block. The applicant further stated that fuse holders inside the enclosure of an active component, such as switchgear, power supplies, power inverters, battery chargers, and circuit boards, are considered to be parts of the larger assembly. Since parts and subcomponents in such enclosure are inspected regularly and maintained as part of the plant's normal maintenance and surveillance activities, they are not subject to an AMR. The applicant identified two fuse holders that will require aging management.

The applicant evaluated the cables and connections as a single component commodity group. Insulated cables and connections that perform an intended function within the scope of license renewal, but are not included in the EQ Program, meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to AMR. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted. The staff agrees that the applicant has correctly identified the cables and connections as a component commodity group that performs its function without moving parts or a change in configuration or properties (passive and long lived), and the cables and connections are therefore subject to an AMR.

2.5.2.3 Conclusion

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the insulated cables and connections that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the insulated cables and connections that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.3 Electrical/Instrumentation and Control Penetration Assemblies

Electrical/I&C penetration assemblies are used to pass electrical circuits through the containment wall while maintaining containment integrity. They provide electrical continuity for the circuit, as well as a pressure boundary for the containment. The pressure boundary function of electrical penetration assemblies is addressed in LRA Table 2.4-1.

2.5.3.1 Summary of Technical Information in the Application

The applicant describes the electrical/I&C penetration assemblies in LRA Section 2.5.3.3. The components of non-EQ electrical penetration assemblies subject to AMR are the organic insulating materials associated with electrical conductors and connections.

Electrical/I&C penetration assemblies included in the EQ Program have a qualified life that is documented. Therefore, electrical/I&C penetration assemblies in the EQ Program do not meet the criteria of 10 CFR 54.21(a)(1)(ii) and are not subject to an AMR.

A review of the electrical/I&C penetration assemblies determined that in addition to the electrical/I&C penetration assemblies included in the EQ Program, additional electrical penetration assemblies are employed at RNP. Except for spare penetrations and one penetration supporting a single out-of-scope circuit, these additional electrical/I&C penetration assemblies were considered to be subject to an AMR whether or not their associated cables are in the scope of license renewal. The penetration supporting the single out-of-scope circuit is of the same design as those covered by the EQ Program. Therefore, electrical penetrations that are not included in the EQ program are considered to meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an AMR except for spare penetrations and one non-EQ penetration containing a single out-of-scope circuit.

2.5.3.2 Staff Evaluation

The staff reviewed Section 2.5 of the LRA to determine whether there is reasonable assurance that the applicant has identified the electrical components within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1). The containment electrical penetrations identified by the applicant as requiring an AMR are non-safety-related (non-EQ) and are used plant-wide to conduct electrical power (voltage and current), either continuously or intermittently between two sections of the electrical/I&C circuits supplying power to various equipment in the containment. The staff reviewed these component categories against the requirements of 10 CFR 54.4(a)(2) and 10 CFR 54.4(b) and found these categories are included in these requirements.

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

2.5.3.3 Conclusions

The staff reviewed the LRA to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the electrical/I&C penetration assemblies that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the electrical/I&C penetration assemblies that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.4 Station Blackout

2.5.4.1 Summary of Technical Information in the Application

In Section 2.5, the applicant identified several components potentially in scope for license renewal—electrical bus, transmission conductors, high-voltage insulators, high-voltage surge arresters, and uninsulated ground conductors. These component types are required to function for recovery from an SBO event. However, the applicant eliminated these components from further consideration based on their not meeting the license renewal scoping requirements of 10 CFR 54.4(a). These component types are required to function for recovery from an SBO.

2.5.4.2 Staff Evaluation

The screening results in Section 2.5 do not include any offsite power system structures or components. The license renewal rule, 10 CFR 54.4(a)(3), requires that all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission regulation for SBO (10 CFR 50.63) be included within the scope of license renewal. The SBO rule, Section 10 CFR 50.63(a)(1), requires that each light-water-cooled power plant licensed to operate be able to withstand and recover from an SBO of a specified duration (the coping duration) that is based upon factors that include "(iii) The expected frequency of loss of offsite power, and (iv) the probable time needed to recover offsite power." The licensee's plant evaluations followed the guidance in NRC RG 1.155 and NUMARC 87-00 to determine if they required plant-specific coping duration. The criteria specified in RG 1.155 to calculate a plant-specific coping duration were based upon the expected frequency of loss of offsite power and the probable time needed to restore offsite power, as well as the other two factors (onsite emergency ac power source, redundancy and reliability) specified in 10 CFR 50.63(a)(1). In requiring that a plant's coping duration be based on the probable time needed to restore offsite power, 10 CFR 50.63(a)(1) specifies that the offsite power system be an assumed method of recovering from an SBO event. Disregarding the offsite power system as a means of recovering from an SBO event would not meet the requirements of the rule and would result in a longer required coping duration. The function of the offsite power system in the SBO rule is, therefore, to provide a means of recovering from the SBO. This system meets the criteria for license renewal within 10 CFR 54.4(a)(3) as a system that performs a function that demonstrates compliance with the Commission's regulations on SBO. Based on this information, the staff requires that applicable offsite power system SCs be included within the scope of license renewal and subject to an AMR, or additional justification for their exclusion must be provided (RAI 2.5.1-1). The staff guidance on scoping of equipment relied on to meet the SBO rule for license renewal is contained in an April 1, 2002, letter to the NEI and the Union of Concerned Scientists.

In response to the staff's RAI 2.5.1-1, the applicant stated on April 28, 2003, that the components comprised by the restoration power path for offsite power from the switchyard are within the scope of license renewal in accordance with the SBO scoping criterion 10 CFR 54.4(a)(3). The first source of offsite power when recovering from an SBO event is the startup transformer (SUT). The SUT is fed from the Unit 1 115-kV switchyard, which has multiple sources of supply from either the Unit 1 115-kV or Unit 2 230 kV switchyards. The SUT east bus 115-kV oil circuit breaker (OCB) and the west bus 115-kV OCB represent the first isolation devices upstream of the SUT and demarcate the RNP 115-kV switchyard from the CP&L transmission and distribution system. The second source of offsite power when recovering from an SBO event is obtained by way of the unit auxiliary transformer (UAT) by backfeeding the main transformers. Prior to backfeeding the main transformers, the main generator connecting straps must be disconnected. The main transformers are fed from the Unit 2 230-kV switchyard, which (like the Unit 1 115-kV switchyard) has multiple sources of supply from either the Unit 1 115-kV or Unit 2 230-kV switchyards. The 230-kV south bus OCB (52-8) and the 230-kV north bus OCB (52-9) represent the first isolation devices upstream of the UAT and demarcate the RNP 230-kV switchyard from the CP&L transmission and distribution system. The offsite power system is discussed in UFSAR Section 8.2.

Additionally, the applicant stated that the electrical components comprised by the restoration power path for offsite power were reviewed, and the passive, long-lived components subject to an AMR include the following:

- generator isolated phase (iso-phase) bus duct
- nonsegregated 4.16-kV & 480-V bus duct
- high-voltage insulators
- switchyard bus
- insulated cables and connections (connectors, splices, terminal blocks)
- transmission conductors and connections

The applicant indicated that due to the bounding approach taken for insulated cables and connections (i.e., no insulated cables and connections were scoped out), even though these systems were initially scoped out, the insulated cables and connections within these scoped-out systems were included in the original RNP AMR.

In the performance of the review, the staff selected system functions described in the UFSAR that were set forth in 10 CFR 54.4 to verify that components having intended functions were not omitted from the scope of the Rule. The staff also focused on components that were not identified as being subject to an AMR to determine if any components were omitted.

2.5.4.3 Conclusions

The staff reviewed the LRA and the applicant's RAI response dated April 28, 2003 for scoping and screening results of SBO components to determine whether any SSCs that should be within the scope of license renewal were not identified by the applicant. No omissions were found. On the basis of this review, the staff concludes that the applicant has adequately identified the components of the SBO system that are within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified the components of the SBO system that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.5 Evaluation Findings

On the basis of the staff's review of the information presented in Section 2.5 of the LRA and the additional information provided by the applicant in response to the staff's RAI, the staff concludes that the applicant has identified those parts of the electrical systems that are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, as required by 10 CFR 54.21(a)(1).

3 Aging Management Review

H.B.Robinson Nuclear Steam Electric Plant, Unit No. 2 (RNP) fully utilized the Generic Aging Lessons Learned (GALL) process found in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report." The purpose of the GALL process is to provide the staff with a summary of staff-approved aging management program (AMPs) for the aging of most structures and components (SCs) that are subject to an aging management review (AMR). If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources used to review an applicant's license renewal application (LRA) will be greatly reduced, thereby improving the efficiency and effectiveness of the license renewal review process. The GALL Report is a compilation of existing programs and activities used by commercial nuclear power plants to manage the aging of SCs within the scope of license renewal and which are subject to an AMR. The GALL Report summarizes the aging management evaluations, programs, and activities credited for managing aging for most of the SCs used throughout the industry. The report also serves as a reference for both applicants and staff reviewers to quickly identify those AMPs and activities that the staff of the United States Nuclear Regulatory Commission (NRC) has determined will provide adequate aging management during the period of extended operation.

The GALL Report identifies (1) structures, systems, and components (SSCs), (2) component materials, (3) the environments to which the components are exposed, (4) the aging effects associated with the materials and environments, (5) the AMPs that are credited with managing the aging effects, and (6) recommendations for further applicant evaluations of aging effects and their management for certain specific component types.

In order to determine whether the GALL process would improve the efficiency of the license renewal review, the staff conducted a demonstration project to exercise the GALL process and to determine the format and content of a safety evaluation based on this process. The results of the demonstration project confirmed that the GALL process will improve the efficiency and effectiveness of the LRA review while maintaining the staff's safety focus. The standard review plan for license renewal (SRP-LR) was prepared based on both the GALL model and the lessons learned from the demonstration project.

During its review of the RNP LRA, the staff performed an AMR inspection from June 9–13, 2003, and from June 23–27, 2003. The purpose of the inspection was to examine activities that support the LRA. It consisted of a selected examination of procedures, representative records, and interviews with the applicant regarding proposed aging management activities. In addition, the inspection team reviewed the proposed implementation of all AMPs credited in the LRA for managing aging. During the AMR inspection, the staff evaluated specific issues raised by staff reviewers. On the basis of the information gathered during the inspection, the staff finds that the applicant has adequately addressed the specific issues raised by the staff reviewers. The inspection issues can be found in the staff's inspection report dated July 31, 2003, and are addressed in this Safety Evaluation Report (SER).

The staff also performed an AMP audit on May 28 and 29, 2003. The purpose of the audit was to verify the consistency of the applicant's AMPs described in the LRA with the AMPs in GALL Report. The audit team evaluated each of the 10 attributes of an applicant's AMP that the applicant claimed were consistent with the related attribute of the associated AMP described in the GALL report. Those AMPs that were not claimed to be consistent with the GALL report, and those attributes that were deviations from the attributes described in the GALL report AMPs, were provided to the NRC staff for review. On the basis of the audit team's review of the AMPs, the staff verifies that the applicant's determination of consistency between the applicant's AMPs and the AMPs described in the GALL Report. The audit issues can be found in the staff's audit report dated August 12, 2003, and addressed in this (SER).

As a result of the staff's review of the RNP application for license renewal, including the additional information and clarifications submitted subsequently, the staff identified two proposed license conditions. The first license condition requires the applicant to include the updated final safety analysis report (UFSAR) Supplement in the next UFSAR update required by 10 CFR 50.71(e) following issuance of the renewed license. The second license condition requires that the future inspection activities identified in the UFSAR Supplement be completed prior to the period of extended operation.

3.0.1 The GALL Format for the License Renewal Application

The RNP LRA closely follows the standard LRA format. However, several important changes within the format reflect the GALL process. First, the tables in LRA Section 2 that identify the SCs that are subject to an AMR now include a third column which links plant-specific SCs in the Section 2 tables to generic GALL component groups in Section 3 (this is discussed in more detail below).

Second, there are no system-specific tables in Section 3 of the RNP LRA. The individual components within a system have been included in a series of system group tables. For example, there are 19 auxiliary systems at RNP. Each system has several components. In the RNP LRA, there are no system tables. Instead all the components in the 19 auxiliary systems are included in one of two auxiliary system tables.

LRA Table 3.3-1 consists of auxiliary system components evaluated in the GALL Report and auxiliary system components that were not evaluated in the GALL Report, but that the applicant has determined can be managed using a GALL AMR and associated AMP. LRA Table 3.3-2 consists of RNP auxiliary system components that were not evaluated in the GALL Report. Similarly, the LRA tables for the other system groups (3.1— reactor systems, 3.2 — engineered safety feature systems, 3.4 — steam and power conversion systems, 3.5 – structures, and 3.6 – electrical systems) have 3.X-1 LRA tables for components evaluated in the GALL Report and for components that were not evaluated in the GALL Report, but that the applicant has determined can be managed using a GALL AMR and associated AMP. Section 3 also includes 3.X-2 LRA tables for components that were not evaluated in the GALL Report.

The first four columns of Table 3.X-1 are derived from Tables 3.1-1 through 3.6-1 of the SRP-LR. The final column provides a discussion of (1) information regarding the applicability of the GALL Report component/commodity group to RNP, (2) any issues recommended in the GALL Report that require further evaluation, (3) details regarding RNP components to be included in the component/commodity group, and (4) a conclusion regarding consistency of the AMR with the GALL Report. A conclusion that the AMR is consistent with the GALL Report means that the combination of component material, environment, aging effect requiring management, and AMR are the same as those specified in Volume 2 of the GALL Report. The RNP considered an AMR to be consistent with the GALL Report despite differences in the names of plant-specific components or commodities provided that the above combination of material, environment, aging effect requiring management, and AMP were the same as those identified in the GALL Report. In some cases, additional components/commodities beyond those listed in the GALL Report have been added, but only if the combination of material, environment, aging effect requiring management, and AMP were the same. In addition, plant-specific information that pertains to the evaluation of the component/commodity group has been included in the discussion column.

The 3.X-2 tables provide information regarding AMPs that are different from or not addressed in the GALL Report. The columns of these tables list component/commodity group, material, environment, aging effect/mechanism, and AMP, and include a discussion of the AMR results. The discussion typically identifies the differences from the GALL Report that form the basis for including the information in Table 3.X-2 instead of Table 3.X-1. Also, the information in these tables includes material/environment combinations that resulted in no aging effects requiring management.

3.0.2 The Staff's Review Process for GALL

The staff's review of the RNP LRA was performed in three phases. In Phase 1, the staff reviewed the applicant's AMP descriptions and compared those AMPs for which the applicant claimed consistency with those reviewed and approved in the GALL Report. For those AMPs for which the applicant claimed consistency with the GALL AMPs, and for which the GALL Report recommended no further evaluation, the staff conducted an audit to confirm that the applicant's AMPs were consistent with the GALL AMPs. For AMPs that were not consistent with the GALL Report, or were not addressed in GALL, the staff's review determined whether the AMPs were adequate to manage the aging effects for which they were credited.

Several RNP AMPs were described by the applicant as consistent with the GALL Report, but with some deviation from GALL. By letter dated February 11, 2003, the staff issued request for additional information (RAI) 3.0-1, requesting the applicant to define the AMP deviations contained in the LRA. By letter dated April 28, 2003, the applicant addressed this RAI by defining the following two types of AMP deviations:

(1) Exceptions to GALL—An exception indicates that the RNP implementing procedure (or other document) does not achieve consistency with some element of the related GALL Chapter XI Program. Justification for the exception is provided.

(2) Enhancements to GALL—An enhancement indicates that the RNP implementing procedure (or other document) requires revision to achieve consistency with some element of the related GALL Chapter XI or SRP-LR Appendix A.1 Program.

For each AMP that had one or more of these deviations, the staff reviewed each deviation to determine (1) whether the deviation is acceptable, and (2) whether the AMP, as modified, would adequately manage the aging effect(s) for which it is credited.

For those AMPs that were not evaluated in the GALL Report, the staff evaluated the AMP against the 10 program elements (Branch Technical Position RLSB-1 in Section A-1 of SRP-

LR, Appendix A).

The staff also reviewed the UFSAR supplement for each AMP to determine whether it provided an adequate description of the program or activity, as required by Section 54.21(d) of Title 10 of the *U.S. Code of Federal Regulations (CFR).*

The AMRs and associated AMPs in the GALL Report fall into two broad categories, (1) those AMRs and associated AMPs that GALL concludes are adequate to manage aging of the components referenced in GALL, and (2) those AMRs and associated AMPs for which GALL concludes that aging management is adequate, but recommends further evaluation for certain aspects of the aging management process. In Phase 2, the staff compared the applicant's AMR results and associated AMPs to the AMR results and associated AMPs reviewed and approved in the GALL Report to determine their consistency. For those AMRs and associated AMPs for which GALL recommended further evaluation, the staff reviewed the applicant's evaluation to determine whether it addressed the additional issues recommended in the GALL report. Finally, for AMRs and associated AMPs that were not consistent with GALL, the staff determined whether the AMRs and associated AMPs were adequate to manage the aging effects for which they were credited.

Once it had determined that the applicant's AMPs were adequate to manage aging, the staff performed Phase 3 of its review by evaluating plant-specific SCs to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis (CLB) for the period of extended operation, as required by 10 CFR 54.21(a)(3). Specifically, this evaluation involved a component-by-component review to determine whether the applicant properly applied the GALL program to the aging management of components within the scope of license renewal and subject to an AMR (i.e., the staff evaluated whether the applicant had properly identified the aging effects, and the AMPs credited for managing these aging effects, for each RNP SC within the scope of license renewal and subject to an AMR). For SCs evaluated in the GALL Report, the staff reviewed the adequacy of aging management against the GALL criteria. For SCs not evaluated in the GALL Report, the staff reviewed the adequacy of aging management against the 10 criteria found in Appendix A of the SRP-LR. Some RNP SCs were not evaluated in GALL, but the applicant determined that the GALL AMR results could be applied and provided justification to support this determination. In these cases, the staff reviewed the adequacy of aging management against the GALL criteria to determine whether the GALL AMPs were adequate to manage the aging effects for which they were credited.

3.0.3 Aging Management Programs

Table 3.0.3-1 presents the common AMP, the associated GALL program, the system groups that credit the program for management of component aging, and the SER section that contains the staff's review of the program.

Table 3.0.3-1 Common Aging Management Programs

Applicant's AMP (LRA section)	Associated GALL AMP	LRA System Groups That Credit the AMP for Aging Management	Staff Evaluation (SER Section)
Metal Fatigue of Reactor Coolant Pressure Boundary (Fatigue Monitoring Program) (B.3.19)	X.M1	3.1—RCS 3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion 3.5—Structures	3.0.3.1
ASME Section XI, Inservice Inspection Subsections IWB, IWC, and IWD Program (B.2.1)	XI.M1	3.1—RCS 3.3—Auxiliary	3.0.3.2
Water Chemistry Program (B.2.2)	XI.M2	3.1—RCS 3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion 3.5—Structures	3.0.3.3
Boric Acid Corrosion Program (B.3.2)	XI.M10	3.1—RCS 3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion 3.5—Structures 3.6—Electrical	3.0.3.4
Flow-Accelerated Corrosion Program (B.3.3)	XI.M17	3.1—RCS 3.4—Steam and Power Conversion	3.0.3.5
Bolting Integrity Program (B.3.4)	XI.M18	3.1—RCS 3.3—Auxiliary	3.0.3.6
Open-Cycle Cooling Water System Program (B.3.5)	XI.M20	3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion	3.0.3.7

Closed-Cycle Cooling Water System Program (B.2.5)	XI.M21	3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion	3.0.3.8
One-Time Inspection Program (B.4.4)	XI.M32	3.1—RCS 3.3—Auxiliary 3.4—Steam and Power Conversion 3.5—Structures	3.0.3.9
Selective Leaching of Materials Program (B.4.5)	XI.M33	3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion	3.0.3.10
Systems Monitoring Program (B.3.17)	Plant-Specific	3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion	3.0.3.11
Preventive Maintenance Program (B.3.18)	Plant-Specific	3.1—RCS 3.2—ESF 3.3—Auxiliary 3.4—Steam and Power Conversion	3.0.3.12

Table 3.0.3-2 presents the system-specific AMPs, the associated GALL program, the system groups that credit the program for management of component aging, and the SER section that contains the staff's review of the program.

Table 3.0.3-2 System-Specific Management Programs

Applicant's AMP (LRA Section)	Associated GALL AMP	LRA System Groups That Credit the AMP for Aging Management	Staff Evaluation (SER Section)
Reactor Head Closure Studs Program (B.2.3)	XI.M3	3.1—RCS	3.1.2.3.1
Nickel-Alloy Nozzle and Penetrations Program (B.4.1)	XI.M11	3.1—RCS	3.1.2.3.2

Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (B.4.2)	XI.M12	3.1—RCS	3.1.2.3.3
PWR Vessel Internals Program (B.4.3)	XI.M16	3.1—RCS	3.1.2.3.4
Steam Generator Tube Integrity Program (B.2.4)	XI.M19	3.1—RCS	3.1.2.3.5
Reactor Vessel Surveillance Program (B.3.11)	XI.M31	3.1—RCS	3.1.2.3.6
Flux Thimble Eddy Current Inspection Program (B.2.8)	Plant-Specific	3.1—RCS	3.1.2.3.7
Inspection of Overhead Heavy-Load and Light-Load (Related to Refueling) Handling Systems (B.3.6)	XI.M23	3.3—Auxiliary	3.3.2.3.1
Fire Protection System (B.3.1)	XI.M26	3.3—Auxiliary	3.3.2.3.2
Fire Water System (B.3.7)	XI.M27	3.3—Auxiliary	3.3.2.3.3
Buried Piping and Tanks Surveillance Program (B.3.8)	XI.M28	3.3—Auxiliary	3.3.2.3.4
Aboveground Carbon Steel Tanks (B.3.9)	XI.M29	3.3—Auxiliary	3.3.2.3.5
Fuel Oil Chemistry Program (B.3.10)	XI.M30	3.3—Auxiliary	3.3.2.3.6
Buried Piping and Tanks Inspection Program (B.3.12)	XI.M34	3.3—Auxiliary	3.3.2.3.7

ASME Section XI, Subsection IWE Program (B.3.13)	XI.S1	3.5—Structures	3.5.2.3.1
ASME Section XI, Subsection IWL Program (B.3.14)	XI.S2	3.5—Structures	3.5.2.3.2
ASME Section XI, Subsection IWF Program (B.2.6)	XI.S3	3.5—Structures	3.5.2.3.3
10 CFR Part 50, Appendix J (B.2.7)	XI.S4	3.5—Structures	3.5.2.3.4
Structures Monitoring Program (B.3.15)	XI.S6	3.5—Structures	3.5.2.3.5
Dam Inspection Program (B.3.16)	Plant-Specific	3.5—Structures	3.5.2.3.6
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.4.6)	XI.E1	3.6—Electrical/I&C	3.6.2.3.1
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.4.7)	XI.E2	3.6—Electrical/I&C	3.6.2.3.2
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Neutron Flux Instrumentation (B.4.8)	ISG-15	3.6—Electrical/I&C	3.6.2.3.2

Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Fuse Holders (B.4.9)	Non-GALL Program	Applicant provided program in response to RAI 2.5.2-1.	3.6.2.3.1
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Bus Duct (B.4.10)	Non-GALL Program	Applicant provided program in response to RAI 2.5.2-2.	3.6.2.1.2

3.0.3.1 Metal Fatigue of Reactor Coolant Pressure Boundary (Fatigue Monitoring Program)

3.0.3.1.1 Summary of Technical Information in the Application

The applicant described its Fatigue Monitoring Program (FMP) in Section B.3.19 of the LRA, "Metal Fatigue of Reactor Coolant Pressure Boundary (Fatigue Monitoring Program)." This program monitors the number of transients that were assumed in the fatigue design. The applicant credits this program with managing the aging of selected components in various nuclear steam supply systems (NSSS) and secondary systems at RNP that are within the scope of license renewal and subject to an AMR.

The LRA states that since the original design of RNP, several transients were discovered at plants worldwide which were not originally considered in the RNP design. Fatigue analyses were performed to account for these additional transients. The analyses demonstrated compliance with American Society of Mechanical Engineers (ASME) Code, Section III fatigue requirements. More recently, cracking of unisolable reactor coolant system (RCS) branch lines has occurred due to thermal stratification and striping. The RNP design has been evaluated against the industry guidelines and no susceptibility to cracking was identified.

The LRA states that the FMP, with the enhancement described above, is consistent with GALL Program X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary," with one exception — the pressurizer surge line was not shown to have an environmentally adjusted cumulative usage factor (CUF) less than 1.0. The LRA states that the fatigue effects on the pressurizer surge line will be managed by periodic examinations in accordance with the ASME, Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program, and that if unacceptable indications are identified, they will be evaluated for continued service of the component.

3.0.3.1.2 Staff Evaluation

In LRA Section B.3.19, "Metal Fatigue of Reactor Coolant Pressure Boundary (Fatigue Monitoring Program)," the applicant described its program to manage fatigue of selected components in various NSSS and secondary systems at RNP. The LRA states that the FMP, with its described enhancement, is consistent with GALL Program X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary," with one exception regarding the pressurizer surge line. The pressurizer surge line was not shown to have an environmentally adjusted CUF less than 1.0; therefore, the pressurizer surge line fatigue effects will be managed by periodic examinations in accordance with the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff confirmed the applicant's claim of consistency during the AMP audit. Furthermore, the staff reviewed the deviation and its justification to determine whether the program, with the deviation, remains adequate to manage the aging effects for which it is credited. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program. In addition, the staff determined whether the applicant properly applied the GALL program to its facility.

In RAI B.3.19-1, the applicant was asked to clarify the scope of the enhancements and identify specific enhancements to the RNP FMP resulting from the industry operating experience (OE) relating to thermal fatigue and component degradation. In its RAI response dated April 28, 2003, the applicant indicated that a fatigue analysis of the pressurizer surge line was performed to consider thermal stratifications described in NRC Bulletin 88-11. This analysis concluded that the largest temperature differences occur during plant heatup and cooldown. Plant-specific evaluations were performed for the stratification transients, based on the same number of heatups and cooldowns as designed. The calculated CUF increased, but remained below the design limit of 1.0, so the FMP was not affected.

In addition, the applicant stated that in 1994, a pressurizer transient occurred that exceeded plant Technical Specifications limits. A detailed evaluation, including the definition of transients and determination of stresses at critical locations, was performed. Locations evaluated included the lower head, heater wells, instrument nozzles, the surge nozzle, and surge nozzle safe end. A fatigue evaluation concluded that the 40-year CUF for each of these components was less than 1.0 and that the out-of-limit transients did not compromise the structural integrity of the pressurizer. The analysis was based upon the use of improved operational practices for future heatups and cooldowns, but included significant margin for additional cycles of insurge/outsurge events beyond past occurrences, so the FMP was not affected.

Further, the applicant stated that monitoring of the surge line was later performed and fatigue analyses were updated to incorporate the measured data resulting in increased CUF. At the limiting location, the RCS hot-leg nozzle, the 40-year CUF was 0.96; therefore, the FMP was not affected.

Finally, the applicant stated that an evaluation of the systems connected to the RCS determined that, due to valve and piping configurations, there are no unisolable piping systems that have the potential for inducing unacceptable thermal stresses as defined in NRC Bulletin 88-08. Therefore, no revisions were made to the fatigue design basis of these lines, and no changes were required for the FMP.

The staff finds that these clarifications are acceptable.

Section B.3.19 of the LRA states that the pressurizer surge line (and the nozzles) was not shown to have an environmentally adjusted CUF less than 1.0, and that fatigue effects will be managed by periodic examinations in accordance with ASME Section XI. In RAI B.3.19-2, the staff asked the applicant to provide an adequate demonstration that the periodic examinations, at the prescribed interval, will be able to detect the initiation of fatigue cracking which could become unstable. The applicant referred to the RNP response to RAI 4.3-10 to address this RAI. The staff's evaluation of this issue is provided in Section 4.3.2.3 of the SER.

In RAI B.3.19-3, the staff asked the applicant to clarify whether the FMP accounts for the environmental effects, and to describe the methodology employed to account for the environmental effects on the CUF calculations at RNP. In its RAI response dated April 28, 2003, the applicant indicated that the FMP tracks the number of thermal cycles that have occurred for each significant thermal transient and compares the cumulative totals to the applicable design limits. The present design limits are based upon the number of thermal cycles postulated in the CLB fatigue analyses. If the CLB fatigue analyses are revised, and if a reduced number of transients is used as an input assumption in the revised analysis, the FMP cycle limit is changed accordingly prior to exceeding the reduced limit.

The applicant further stated that the FMP will account for environmental effects prior to the period of extended operation. Environmental fatigue calculations were performed for the seven locations specified in NUREG/CR-6260 and for seven locations inside the pressurizer using the F_{en} methodology contained in NUREG/CR-6583 for carbon/low-alloy steel material and in NUREG/CR-5704 for stainless steel (SS) material. The number of load/unload cycles used as an input to one of the environmental fatigue calculations was reduced from 29,000 to 19,000, and the applicant intends that the FMP limit for load/unload cycles will be reduced accordingly prior to the period of extended operation, thereby incorporating the environmental fatigue calculations into the FMP. The UFSAR Supplement provided in the LRA refers to this change. The applicant also stated that the pressurizer surge line components, which have not been shown to have an environmentally adjusted CUF less than 1.0, will be managed separately by the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program as described in RNP Response to RAI 4.3-10. The staff's evaluation of this issue is provided in Section 4.3.2.3 of the SER.

The staff views this AMP as a cycle counting program and finds the above method of adjusting the number of cycles to be acceptable.

3.0.3.1.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.2 ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program

3.0.3.2.1 Summary of Technical Information in the Application

The applicant's inservice inspection (ISI) program is discussed in LRA Section B.2.1, "ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program." The applicant stated that the program is consistent with GALL XI.M1, "ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD." The applicant further stated that its program is effective in managing aging effects such as cracking, loss of preload due to stress relaxation or irradiation creep, loss of material, and reduction of fracture toughness due to thermal embrittlement.

As part of the operating experience, the applicant stated that the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program, now in its fourth 10-year interval, is effectively implemented to meet regulatory and procedural requirements, including periodic reviews. The applicant assigns qualified personnel and provides adequate resources to manage the program. The program is continually upgraded based on industry experience and research. This AMP has been effective in ensuring pressure boundary integrity of the RNP Class 1, 2, and 3 systems.

On the basis of the above discussion, the applicant concluded that the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program provides reasonable assurance that the aging effects will be adequately managed such that the ASME Class 1, 2, and 3 components will continue to perform their intended functions consistent with the CLB for the period of extended operation.

3.0.3.2.2 Staff Evaluation

The applicant stated that this program is consistent with GALL XI.M1, "ASME Section XI: Inservice Inspection, Subsections IWB, IWC, and IWD Program," with no deviations. The staff confirmed the applicant's claim of consistency during the AMP audit. The staff concludes that the applicant's program is consistent with the GALL program. There is no need, therefore, for the staff to review the attributes in the applicant's ISI program, with the exception of plant-specific operating experience.

The staff, however, requested additional information in regard to the discussion section of Item 2 in LRA Table 3.1-1 which focuses on the issue raised in Information Notice (IN) 90-04 and addressed in Item D1.1-c of GALL Table IV.D1 pertaining to the reliability of an ultrasonic examination of the steam generator (SG) upper shell-to-transition cone girth weld in the presence of a geometric irregularity (RAI B.2.1-1). The applicant, in its response dated April 28, 2003, stated that ultrasonic test (UT) indications have been found and were verified by surface examination during the current license term. The applicant has provided for augmented inspection of the upper shell-to-transition weld during the fourth 10-year inspection interval, in addition to the normally scheduled ISI of the weld. The staff accepts the applicant's evaluation that the proposed examinations under the CLB will ensure reliable detection of the aging effects addressed in LRA Table 3.1-1 of the subject welds so that the component will perform its intended function during the period of extended operation. However, since this augmentation of the ISI program has only been implemented by the applicant for the current 10-year inspection interval for RNP, the staff seeks confirmation that the applicant is committed to implement the augmented inspections of the SG upper shell-to-transition cone weld during the two 10-year ISI intervals for the extended period of operation for RNP. This is Confirmatory Item 3.0.3.2.2-1.

In response to Confirmatory Item 3.0.3.2.2-1 the applicant stated that " RNP will continue to perform examinations of the steam generator transition girth welds as required by ASME Section XI during the period of extended operation."

The applicant's response to Confirmatory Item 3.0.3.2.2-1 confirms that the applicant will continue to perform the required ultrasonic examinations of the SG shell-to-transition cone girth welds during the two 10-year ISI intervals that are scheduled for the extended period of operation. This resolves Confirmatory Item 3.0.3.2.2-1 and Confirmatory Item 3.0.3.2.2-1 is closed.

The staff reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.3 Water Chemistry Program

3.0.3.3.1 Summary of Technical Information in the Application

The applicant discusses its AMP for water chemistry in LRA Section B.2.2, "Water Chemistry Program." The Water Chemistry Program is credited for aging management of selected components in systems and structures at RNP. The following aging effects and mechanisms are of concern:

- cracking due to stress-corrosion cracking, IASCC
- loss of material due to erosion, fretting, pitting corrosion, crevice corrosion, general corrosion, and galvanic corrosion
- loss of heat transfer effectiveness due to fouling of heat transfer surfaces

The applicant had several operating experiences relating to limits for the water chemistry parameters that would not affect component intended functions for license renewal or could be considered suggestions for program improvements. In those instances in which a chemistry action level was exceeded, the applicant took prompt corrective actions to reestablish proper chemistry.

The applicant stated that it received an NRC notice of violation for "Failure to Take Adequate Corrective Action to an Out-of-Specification BAST (Boric Acid Storage Tank) Boron Concentration." This item was closed out when the NRC inspectors determined that RNP corrective actions had been adequately implemented. The applicant states that no chemistry-related degradation has resulted in loss of component intended functions on any systems for which water chemistry is actively controlled.

The applicant states that the program is consistent with GALL XI.M2, "Water Chemistry," except that (1) the applicant identified an aging mechanism for this program that was not identified in the GALL Report (loss of heat transfer effectiveness due to fouling of heat transfer surfaces), and (2) the program implements a later revision of the Electric Power Research Institute (EPRI) guidelines for primary and secondary water chemistry than those recommended in the GALL Report.

The applicant concludes that the Water Chemistry Program is consistent with GALL XI.M2 and implementation of the program provides reasonable assurance that the aging effects will be managed such that the components within the scope of license renewal will continue to perform their intended functions consistent with the CLB for the period of extended operation.

3.0.3.3.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.2.2 to ensure that the aging effects caused by cracking, corrosion, erosion, fretting, and fouling will be adequately managed so that the intended functions of affected SSCs will be maintained consistent with the CLB throughout the period of extended operation. The staff confirmed the applicant's claim of consistency during the AMP audit. In addition, the staff determined whether the applicant properly applied the GALL program to its facility.

The 10 program attributes in GALL XI.M2 provide detailed programmatic characteristics and criteria that the staff considers necessary to manage aging effects due to the water chemistry in the safety systems and components. The applicant has stated that the program attributes for the Water Chemistry Program are consistent with those specified in GALL XI.M2, with exceptions regarding loss of heat transfer effectiveness due to fouling of heat transfer surfaces and the version of EPRI guidelines used. The staff finds that the exception concerning loss of heat transfer effectiveness is acceptable because it is an additional aging mechanism that the applicant is adding onto the program. The applicant retains the program description on record at RNP.

The staff has inspected the program onsite at RNP for acceptability and compared the program's 10 attributes to the 10 attributes described in GALL XI.M2. Inspections of LRA scoping analyses, AMRs, and AMPs are a normal part of NRC's process for reviewing LRAs. Furthermore, the staff has reviewed the enhancements to determine whether the program remains adequate to manage the aging effects for which it is credited, and reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program. In letters dated April 28 and June 13, 2003, the applicant responded to the staff's RAI B.2.2-1 concerning the version of EPRI guidelines implemented in the RNP Water Chemistry Program. The staff's RAI and the applicant's responses are discussed below.

In LRA B.2.2, the applicant stated that the Water Chemistry Program implements a later revision of the EPRI guidelines for primary and secondary water chemistry than that specified in GALL. In RAI B.2.2-1, the staff asked the applicant to discuss whether any differences exist between the applicant's Water Chemistry Program and GALL XI.M2. In its response to RAI B.2.2-1, the applicant stated that the differences have no adverse effects on the ability of the program to manage aging effects, and they are not considered to be actual exceptions to the elements of the Water Chemistry Program described in the GALL Report. The RNP Water Chemistry Program is based on the current, approved revisions of EPRI guidelines as prescribed by Nuclear Energy Institute (NEI) 97-06, "Steam Generator Program Guidelines." The applicant stated that NRC Generic Letter (GL) 97-05, "Steam Generator Tube Inspection Guidelines," requires pressurized-water reactor (PWR) licensees to verify that licensee steam generator (SG) tube inspection practices are consistent with existing regulatory requirements and plant licensing bases. In response to the GL 97-05, the applicant committed to implement the guidance of NEI 97-06 with the exceptions described in RNP correspondence. By letter dated August 13, 1998, the NRC did not find any concerns relative to compliance with the RNP licensing basis for the SG tube inspection techniques in response to GL 97-05.

The RNP's Steam Generator Program implements these guidelines, including water chemistry, and allows deviations from industry guidelines. This program allows local deviations to industry guidelines or industry recommendations whether they be in the inspection, repair, or chemistry arenas. Such deviations are allowed by paragraph 1.1 of EPRI TR-107569-V1 through the use of a documented technical justification for each deviation or through application of performance-based criteria and risk-based methodologies. The applicant stated that use of technically justified deviations is allowed by the industry guidelines; therefore, deviations are not considered inconsistent.

The staff finds the applicant's response to RAI B.2.2-1 acceptable because the applicant has shown that the differences in the versions of EPRI guidelines have no adverse effects on its Water Chemistry Program.

In LRA B.2.2, the applicant stated that the Water Chemistry Program has been subject to periodic internal assessment activities. In RAI B.2.2-2, the staff requested the applicant to explain the kind of activities that were performed and the results of the activities. In its response to RAI B.2.2-2, the applicant stated that its Water Chemistry Program is subject to periodic performance-based assessments which involve a review of the program for efficacy. Typically, this consists of a combination of assessments, such as document review, interviews, and field observations. Subject matter experts are also used to aid in these assessments. The results of these assessments are captured as part of the Corrective Action Program, and condition reports are generated to track suggested program improvements and/or program deficiencies.

The applicant's Progress Energy Quality Assurance Program Manual, NGGM-PM-0007, requires that assessments be performed at nuclear plants and company locations where functions affecting safety-related activities are performed. In addition, assessments are regularly scheduled on the basis of the status and safety importance of the activity being performed. These assessments verify compliance, determine effectiveness, and evaluate the Quality Assurance Program against performance objectives and Quality Assurance Program requirements. The assessment frequencies are based on the RNP technical specifications, UFSAR commitments, and Quality Assurance Program manual requirements. The program manual states that assessments should focus on areas of potential improvement based on indicators such as previous assessment data, industry experience, regulatory sensitivity, and input from management.

The staff finds the applicant's response to RAI B.2.2-2 acceptable because the applicant's assessment activities are consistent with GALL XI.M2.

In LRA B.2.2, the applicant stated that it has developed a one-time inspection to demonstrate the adequacy of the water chemistry controls. In RAI B.2.2-3, the staff asked the applicant to provide the criteria that were used to select which piping will be evaluated to confirm the effectiveness of the Water Chemistry Program. In its response to RAI B.2.2-3, the applicant stated that a one-time inspection will be performed on selected components at susceptible locations covered under the Water Chemistry Program. Inspections will include internal visual or volumetric examinations to determine if loss of material or cracking has occurred. The results of these inspections will be used to assess the condition of the components in question and reviewed against assumptions made regarding the effectiveness of water chemistry controls in support of license renewal. Acceptance criteria will be based on construction code, manufacturers' recommendations, engineering evaluation, or metallurgical examination, as appropriate.

The staff finds the applicant's response to RAI B.2.2-3 acceptable because the applicant will perform a one-time inspection before entering the period of extended operation at representative locations for each of the line items identified by GALL and because the inspection is consistent with GALL XI.M2.

3.0.3.3.3 UFSAR Supplement

In LRA Section A.3.1.2, "Water Chemistry Program," the applicant provides a UFSAR Supplement summary for the Water Chemistry Program. The UFSAR Supplement states that the Water Chemistry Program is used to mitigate aging effects on component surfaces that are exposed to water as process fluid. Chemistry programs are used to control water chemistry for impurities that accelerate corrosion and contaminants that may cause loss of heat transfer due to fouling heat transfer surfaces. This program relies on monitoring and control of water chemistry to keep peak levels of various contaminants below the system-specific limits. Alternatively, chemical agents such as corrosion inhibitors, oxygen scavengers, and biocides may be introduced to prevent certain aging mechanisms. The RNP Water Chemistry Program is based on the current revisions of EPRI PWR Water Chemistry Guidelines and EPRI PWR

Secondary Water Chemistry Guidelines.

The staff finds that the summary in the UFSAR Supplement is consistent with LRA Section B.2.2, "Water Chemistry Program," and is, therefore, acceptable.

3.0.3.3.4 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.4 Boric Acid Corrosion Program

3.0.3.4.1 Summary of Technical Information in the Application

The applicant discusses its AMP for boric acid corrosion in LRA Section B.3.2, "Boric Acid Corrosion Program." The applicant states that the AMP is consistent with GALL XI.M10, "Boric Acid Corrosion." The Boric Acid Corrosion Program is credited for aging management of components in systems and structures exposed to boric acid at RNP.

The aging effects and mechanisms of concern are (1) loss of material due to aggressive chemical attack and general, crevice, and pitting corrosion, and (2) loss of mechanical closure integrity due to loss of material from aggressive chemical attack.

As a result of its license renewal review, the applicant enhanced the scope of the program to (1) ensure that mechanical, structural, and electrical components which are within the scope for license renewal are covered, and (2) identify additional areas in which components may be susceptible to exposure from boric acid (e.g., containment, auxiliary, and spent fuel buildings).

The applicant stated that boric acid leakage from the pressurizer is managed in accordance with ASME Section XI, Category B-P, as well as the Boric Acid Corrosion Program.

The applicant reviewed its condition report database and determined that most plant operating events involving the Boric Acid Corrosion Program dealt with improvements to the inspection methods and acceptance criteria resulting from evaluations of leaks that occurred in plant systems. The applicant also reviewed the NRC inspection reports related to boric acid corrosion at RNP. The applicant received an NRC citation of violation for "Failure to Provide

Adequate Work Instruction for Degraded Stud Inspection." This violation involved failure to establish adequate work instructions (procedures) requiring direct or indirect visual inspection of the C reactor coolant pump (RCP) studs after the removal of boric acid residue and corrosion products. In its response to the NRC citation, the applicant revised the Boric Acid Corrosion Program.

3.0.3.4.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.3.2 to ensure that the aging effects caused by boric acid corrosion will be adequately managed so that the intended functions of affected SSCs will be maintained consistent with the CLB throughout the period of extended operation. The staff confirmed the applicant's claim of consistency during the AMP audit. In addition, the staff determined whether the applicant properly applied the GALL program to its facility.

The 10 program attributes in GALL XI.M10 provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage aging effects due to boric acid corrosion in the safety systems and components. Although the applicant did not provide the program attribute descriptions in Section LRA B.3.2, the applicant has stated that the attributes for the Boric Acid Corrosion Program are consistent with those specified in GALL XI.M10. The applicant retains the program description on record at RNP.

The staff has inspected the Boric Acid Corrosion Program onsite at RNP for acceptability and compared the program's 10 attributes to the 10 attributes described in GALL XI.M10. Inspections of LRA scoping analyses, AMRs, and AMPs are a normal part of NRC's process for reviewing LRAs. Furthermore, the staff has reviewed the enhancements to determine whether the program remains adequate to manage the aging effects for which it is credited, and reviewed the UFSAR Supplement to determine whether it provides an adequate description for the revised program. In letters dated April 28 and June 13, 2003, the applicant responded to the staff's request of additional information. The staff's request for additional information and the applicant's responses are discussed below.

In LRA B.3.2, there is no discussion of strategies that address boric acid leak management for component segments that are inaccessible to visual inspection at the RNP. In RAI B.3.2-1, the staff asked the applicant to discuss whether the Boric Acid Corrosion Program includes provisions to inspect, detect, or monitor boric acid leakage in inaccessible locations.

In its response to RAI B.3.2-1, the applicant stated that its response to NRC Bulletin 2002-01, dated April 1, 2002, provides a description of pertinent aspects of the RNP Boric Acid Corrosion Program. The applicant also responded to a staff's RAI issued on Bulletin 2002-01 by letter dated January 31, 2003. In its responses to Bulletin 2002-01, the applicant did not identify any areas that are inaccessible for performing boric acid walkdowns. The applicant also stated that visual examinations may be conducted without removal of insulation. However, for leakage examinations of components with external insulation surfaces and joints not accessible for direct visual examination, the surrounding area (including the floor, equipment surfaces underneath the inaccessible component, and other areas where leakage may be channeled) shall be examined for evidence of component leakage. Discoloration, staining, boric acid residue, and other evidence of leakage on insulation surfaces and the surrounding area will be given particular consideration as evidence of component leakage. If evidence of leakage is found, removal of insulation to determine the exact source may be required. When leakage is discovered, the leak/spray path will be investigated, removing insulation as necessary, to determine the extent of any component degradation.

The staff finds the applicant's response to RAI B.3.2-1 acceptable because the applicant's inspection approach for the inaccessible components is consistent with GALL XI.M10.

NRC GL 88-05 provides guidance on monitoring the condition of the reactor coolant pressure boundary (RCPB) for borated water leakage. NRC IN 86-108, and the associated three supplements, give information on the degradation of RCS pressure boundary resulting from boric acid corrosion. In RAI B.3.2-2, the staff asked the applicant to discuss whether the Boric Acid Corrosion Program at RNP is consistent with GL 88-05, and whether the program addresses the concerns in IN 86-108.

In its response to RAI B.3.2-2, the applicant cited Subsection A.3.1.10 of its UFSAR Supplement. For GL 88-05, the UFSAR Supplement notes that the Boric Acid Corrosion Program was implemented in response to GL 88-05. The applicant's response to NRC Bulletin 2002-01, dated April 1, 2002, provides a discussion of the RNP Boric Acid Corrosion Program relative to GL 88-05 requirements. In its April 1, 2002, letter, the applicant stated that, "...RNP maintains a program for the implementation of NRC GL 88-05. This program is implemented by program and surveillance procedures. Effective implementation of these program procedures was demonstrated during Refueling Outage (RFO)-20 in response to the identification of a control rod drive mechanism (CRDM) canopy seal weld leak. These program and surveillance procedures are consistent with NRC GL 88-05." The program procedure outlines specific activities and inspection boundaries and supplements the requirements of other surveillances for the inspection and disposition of borated system leakage and any resultant corrosion of primary pressure boundary components.

With regard to NRC IN 86-108, the applicant stated that its implementation of NRC GL 88-05 addresses IN 86-108 through Supplement 3.

The staff finds the applicant's response to RAI B.3.2-2 acceptable because the applicant has shown that its program meets GL 88-05 and addressed the issues in IN 86-108.

The NRC has issued GL 97-01 and Bulletins 2001-01, 2002-01, and 2002-02 regarding reactor vessel (RV) head degradation caused by boric acid leakage. In RAI B.3.2-3, the staff asked the applicant to discuss any steps that have been taken in the RNP Boric Acid Corrosion Program to reflect the staff's concerns and recommendations in the aforementioned NRC generic communications. The applicant responded to RAI B.3.2-3 as follows.

By letters dated July 29, 1997, and February 1, 1999, the applicant provided responses to GL 97-01. Further discussion regarding this matter is also included in the RNP response to RAI B.4.1-1. No revision to the Boric Acid Corrosion Program was indicated by the subject correspondence. The staff notes that GL 97-01 has been superceded by the following NRC generic communications and Orders.

Bulletin 2001-01

In letters dated September 4, October 2, October 19, and November 12, 2001, and December 13, 2002, the applicant stated that it has taken the following three steps to satisfy the recommendations specified in Bulletin 2001-01:

- In its September 4, 2001, letter, the applicant provided information to demonstrate that RNP was in compliance with applicable regulatory requirements, and to provide assurance regarding the structural integrity of vessel head penetration (VHP) nozzles. In its November 12, 2001, letter, the applicant committed to provide the NRC with a plan for nondestructive examination (NDE) of the RNP VHP nozzles at least 60 days prior to the start of RFO-21.

- In its September 4, 2001, letter, the applicant stated that during the RFO-20 in May 2001, it performed, (a) extensive visual examinations of the RV head, (b) removal of the RV head shroud and insulation for these visual examinations resulting in the performance of a bare metal visual examination, and (c) cleaning of the RV head in support of these visual examinations.

- No evidence of VHP nozzle leakage or any other sources of RCS pressure boundary leakage were identified. The effort expended during RFO-20 to clean and visually examine the RV head provides a sound baseline for future examinations.

Bulletin 2002-01

In letters dated April 1, May 17, and December 13, 2002, and January 31, 2003, the applicant provided the following information to satisfy the request for information in Bulletin 2002-01:

- Information related to the integrity of the reactor coolant pressure boundary, including the reactor pressure vessel (RPV) head and the extent to which inspections have been undertaken to satisfy applicable regulatory requirements

- The basis for concluding that RNP satisfies applicable regulatory requirements related to the structural integrity of the reactor coolant pressure boundary and the extent to which future inspections will ensure continued compliance with applicable regulatory requirements

- The basis for concluding that the Boric Acid Corrosion Program is providing reasonable assurance of compliance with the applicable regulatory requirements discussed in GL 88-05 and Bulletin 2002-01

- The results of the bare metal qualified visual examination which determined that the 69 VHP nozzles were acceptable with no degradation, cracking, or leakage identified. Because no degradation of the RPV head was identified, no corrective action or root cause determinations were necessary

Bulletin 2002-02

In letters dated August 12, September 9, and December 13, 2002, the applicant provided the following information as requested in Bulletin 2002-02:

- The applicant plans to supplement the Reactor Pressure Vessel Inspection Program with nonvisual NDE. The RPV inspection plan for the RFO-21 was provided to the NRC by letter dated August 12, 2002.

- The schedule and frequency for NDEs during future refueling outages (i.e., refueling outages subsequent to RFO-21) will be established following careful review of such factors as the RFO-21 inspection results, industry information that becomes available as similar examinations are completed at other facilities, improvements in industry understanding of examination techniques and crack growth rates, and the possibility of procuring a replacement RPV head.

- The bare metal qualified visual examination of the RPV head and head penetration nozzles did not identify evidence of VHP nozzle leakage or cracking.

- The NDE of the RPV head penetration nozzles found no evidence of service-related degradation.

NRC Order EA-03-009

On February 11, 2003, the NRC issued Order EA-03-009 establishing interim inspection requirements for RPV heads at PWRs. The inspection requirements were based on effective degradation years and categorized licensees based on the susceptibility of the RPV head in their plants to degradation via primary water stress-corrosion cracking (PWSCC). The staff is reviewing the applicant's responses to the orders in an effort separate from the license renewal review process.

In LRA B.3.2, the applicant stated that as a result of its license renewal review, the scope of the Boric Acid Corrosion Program will be enhanced to identify additional areas in which components may be susceptible to exposure from boric acid (e.g., containment, auxiliary, and spent fuel buildings). In RAI B.3.2-4, the staff requested the applicant to (1) provide a list of specific areas (i.e., buildings) that will be covered by the Boric Acid Corrosion Program, (2) specify which piping systems and components will be covered by the Boric Acid Corrosion Program, and (3) describe the Boric Acid Corrosion Program.

In its response to RAI B.3.2-4, the applicant stated that its Boric Acid Corrosion Program is described in detail in the May 17, 2002, letter to the NRC as a part of the applicant's response to Bulletin 2002-01. The letter contains detailed information regarding the Boric Acid Corrosion Program, including SSCs that are susceptible to exposure from boric acid.

The staff is reviewing the applicant's Boric Acid Corrosion Program and RPV head inspection with respect to the above NRC generic communications and Orders. Any future regulatory actions that may be required as a result of the review will be addressed by the staff in a separate regulatory action. The issue is considered a current operating issue and will be handled as such. The staff will resolve this issue in accordance with 10 CFR 54.30 outside of the license renewal process. Therefore, the staff considers RAI B.3.2-3 and RAI B.3.2-4 closed.

In LRA B.3.2, the applicant stated that boric acid leakage from the pressurizer is managed by the Boric Acid Corrosion Program and by the ASME code inspection specifications. In RAI B.3.2-5, the staff asked the applicant to address why the SGs and RPV are not included in the Boric Acid Corrosion Program. In its response to RAI B.3.2-5, the applicant clarified that the steam generators and RPV are included in the Boric Acid Corrosion Program as discussed in Item 26 in LRA Table 3.1-1. The staff finds the applicant's response to RAI B.3.2-5 acceptable because the SGs and RPV are included in the Boric Acid Corrosion Program. This is consistent with the commodity group in GALL 2.3.

3.0.3.4.3 UFSAR Supplement

In Section A.3.1.10, "Boric Acid Corrosion Program," of the LRA, the applicant provides an UFSAR Supplement summary for the Boric Acid Corrosion Program. The UFSAR Supplement description for the program states that the Boric Acid Corrosion Program manages the aging effects for susceptible materials of SCs that perform a license renewal intended function and that are exposed to the effects of borated water leaks. The program consists of (1) visual inspection of external surfaces that are potentially exposed to borated water leakage, (2) timely discovery of leak path and removal of the boric acid residues, (3) assessment of the damage, and (4) followup inspection for adequacy of corrective actions. This program is implemented in response to NRC GL 88-05.

Prior to the period of extended operation, the scope of the Boric Acid Corrosion Program will be expanded to (1) ensure that the mechanical, structural, and electrical components in scope for license renewal are covered, and (2) identify additional areas in which components may be susceptible to exposure from boric acid (e.g., containment, auxiliary, and spent fuel buildings).

The staff finds that the summary in the UFSAR Supplement is consistent with LRA Section B.3.2, "Boric Acid Corrosion Program" and is, therefore, acceptable.

3.0.3.4.4 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by

10 CFR 54.29(a).

3.0.3.5 Flow Accelerated Corrosion Program

3.0.3.5.1 Summary of Technical Information in the Application

The applicant discusses its AMP for flow-accelerated corrosion (FAC) in LRA Section B.3.3, "Flow-Accelerated Corrosion Program." The applicant states that the AMP is consistent with GALL XI.M17, "Flow-Accelerated Corrosion." The Flow-Accelerated Corrosion Program is credited for aging management of selected carbon steel and low alloy steel piping and components in secondary systems at RNP. The aging effect/mechanism of concern is loss of material due to FAC and erosion.

As a result of its license renewal review, the applicant will enhance the program elements for *Scope of Program* and *Corrective Actions* as specified in GALL. The applicant identified components that may be susceptible to FAC or to erosion. These components will be added to the program scope. Also, the applicant will revise administrative controls for the program to mandate that corrective actions be taken in accordance with the Corrective Action Program in the GALL Report when certain acceptance criteria are not met.

The applicant implemented and maintained the Flow-Accelerated Corrosion Program in accordance with the general requirements for engineering programs. This provides assurance that the programs (1) are effectively implemented to meet regulatory, process, and procedure requirements, including periodic reviews, (2) have qualified personnel as program managers who are given authority and responsibility to implement the program, (3) commit adequate resources to program activities, and (4) are managed in accordance with plant administrative controls.

Since the advent of NRC GL 89-08, the Corrective Action Program has been effective in ensuring that the Flow-Accelerated Corrosion Program is continually improving. Several condition reports have been generated as a result of as-found conditions or as a result of assessments. These reports have led to improvements in the Flow-Accelerated Corrosion Program. The applicant also improved the Flow-Accelerated Corrosion Program as a result of NRC inspections.

The applicant concludes that the Flow-Accelerated Corrosion Program, with the enhancements identified above, is consistent with GALL XI.M17 and implementation of the program provides reasonable assurance that the aging effects will be managed such that the components within the scope of license renewal will continue to perform their intended functions consistent with the CLB for the period of extended operation.

3.0.3.5.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.3.3 to ensure that the aging effects caused by FAC will be adequately managed so that the intended functions of affected SSCs will be maintained consistent with the CLB throughout the period of extended operation. The staff confirmed the applicant's claim of consistency during the AMP audit. In addition, the staff determined whether the applicant properly applied the GALL program to its facility.

The 10 program attributes in GALL XI.M17 provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage aging effects due to FAC. Although the applicant did not provide the program attribute descriptions for the Flow-Accelerated Corrosion Program in LRA Section B.3.3, the applicant has stated that the program attributes are consistent with those specified in GALL XI.M17. The applicant retains the program description on record at RNP.

The staff has inspected the RNP program on site for acceptability and compared the program's 10 attributes to the 10 attributes described in GALL XI.M17. Inspections of LRA scoping analyses, AMRs, and AMPs are a normal part of the NRC's process for reviewing LRAs. Furthermore, the staff has reviewed the enhancements to determine their acceptability. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the Flow-Accelerated Corrosion Program. In letters dated April 28 and June 13, 2003, the applicant responded to several of the staff's requests for additional information. The staff's requests for additional information and the applicant's responses relative to the Flow-Accelerated Corrosion Program are discussed below.

In RAI B.3.3-1, the staff requested the applicant to discuss FAC problems that have occurred at RNP, describe the current Flow-Accelerated Corrosion Program, and discuss the effectiveness of the Flow-Accelerated Corrosion Program in resolving the past FAC occurrences. In its response to RAI B.3.3-1, the applicant stated that the purpose of the Flow-Accelerated Corrosion Program is to develop a standardized method of identifying, inspecting, and evaluating piping systems that are susceptible to FAC. This program satisfies a regulatory commitment made by the applicant to the NRC, in response to NRC Bulletin 87-01 and NRC GL 89-08, regarding implementation of a long-term FAC monitoring program. Under the Flow-Accelerated Corrosion Program, the applicant reviews plant systems for susceptibility. In general, secondary (steam cycle) systems are considered susceptible to FAC wear, except those that are SS. Alloy piping with chromium content greater than 1 percent is 10 times more resistant to FAC than carbon steel, but such piping has been included in the initial program until the expected low wear rates are verified.

The Flow-Accelerated Corrosion Program is credited with managing aging effects for components within a number of systems within the scope of license renewal (including components identified as in scope per 10 CFR 54.4(a)(2)), including the SG blowdown system; main steam; extraction steam system; auxiliary boiler/steam system; feedwater system; heater vents, drains, and level control; condensate system; SGs; and auxiliary feedwater (AFW) system.

The applicant responded that the RNP Flow-Accelerated Corrosion Program is based on the criteria identified in the EPRI report, NSAC-202L-R2, as recommended by GALL. As stated in LRA B.3.3, the Flow-Accelerated Corrosion Program is consistent with GALL XI.M17. This determination is based on an evaluation of the RNP Flow-Accelerated Corrosion Program with respect to each of the program elements in GALL XI.M17.

The applicant has identified and repaired several problem areas at RNP as a result of the Flow-Accelerated Corrosion Program, including wall thinning of pipe due to FAC in the following areas (1) high-pressure steam extraction lines—100 percent of this piping was replaced with FAC-resistant piping (SS or low-alloy steel), (2) reheater drains—99 percent of piping was replaced with FAC-resistant pipe, (3) condensate system—100 percent inspection coverage with limited replacement and ongoing monitoring and trending, (4) small bore drains—100 percent replaced with FAC-resistant piping, and (5) 2" blowdown piping—100 percent replaced with FAC-resistant piping.

The applicant stated that the effectiveness of the Flow-Accelerated Corrosion Program has been demonstrated by a decrease in iron transport measurements. Also, there has been no evidence of FAC-related leaks in more than 2 years. This is in contrast to 15 identified FAC-related leaks during the period from January 1990 to November 1999. Another example of effectiveness in resolving FAC problems is documented in the NRC's Integrated Inspection Report No. 50-261/98-02. In this report, the NRC inspected wall thinning in steam generator "A" nozzle to a reducer. This inspection found records of the FAC test to be complete and accurate. The NRC inspector found that the applicant properly evaluated and dispositioned problem areas.

The staff finds the applicant's response to RAI B.3.3-1 acceptable because the applicant has identified and repaired the appropriate system piping that is covered under the Flow-Accelerated Corrosion Program.

In RAI B.3.3-2, the staff asked the applicant to (a) identify all components and systems that are covered in the program scope, (b) discuss the enhancement(s) to the program elements for *Scope of Program* and *Corrective Actions*, and (c) describe the program improvements made as a result of the NRC inspections and provide the reference of the NRC inspection reports.

In its response to RAI B.3.3-2a, the applicant stated that during the AMR process, several components were identified that were not in the current RNP Flow-Accelerated Corrosion Program. These components are included in the scope of the enhanced Flow-Accelerated Corrosion Program (see below).

In its response to RAI B.3.3-2b, the applicant stated that components not specifically identified in the current site program will be added to site program documents. These components were identified during the AMR process and include steam nozzles, feedwater nozzles, SG nozzle thermal sleeves, and temperature elements (thermowells). The program will be enhanced to inspect for erosion wear in locations deemed to be susceptible by the system engineer. The FAC predictive model considers valves to be high-wear components. Downstream piping is used as a "leading indicator" for valves deemed to be susceptible to FAC wear. The applicant will revise the Flow-Accelerated Corrosion Program before entering into the extended period of operation to add a section dedicated specifically to valves. An additional requirement will be added to program procedures to require material alloy analysis for potentially susceptible valves. For corrective actions, the Flow-Accelerated Corrosion Program procedure will be revised to state that a condition report "shall" be initiated in accordance with the Corrective Action Program for throughwall failures, or when actual wall thickness is found to be substantially less than the expected value.

In its response to RAI B.3.3-2c, the applicant stated that an NRC inspection was performed from April 27 to May 1, 1992, which resulted in NRC Inspection Report No. 50-261/92-13. The

NRC found the Flow-Accelerated Corrosion Program at the time to be weak with little corporate direction and a need for program enhancements. The NRC performed a followup inspection in September 1993 and noted significant program improvements as discussed in NRC Inspection Report No. 50-261/93-20.

The staff finds the applicant's response to RAI B.3.3-2 acceptable because the applicant has enhanced and strengthened the Flow-Accelerated Corrosion Program consistent with GALL XI.M17.

In LRA B.3.3, the applicant stated that "administrative controls for the program will be revised to mandate that corrective actions be taken in accordance with the corrective action program when certain acceptance criteria are not met." In RAI B.3.3-3, the staff asked the applicant to (a) clarify whether the above statement is consistent with GALL XI.M17 because in GALL XI.M17 the administrative controls element is not related to the corrective actions element, and (b) discuss the "certain acceptance criteria" that may not be met.

In its response to RAI B.3.3-3a, the applicant stated that the statement in question is referring to the license renewal evaluation of the Corrective Action Program element for the RNP Flow-Accelerated Corrosion Program. The "administrative controls" delineated in the RNP Flow-Accelerated Corrosion Program procedure currently state that a condition report "should" be initiated in accordance with Corrective Action Program procedures whenever a throughwall failure (leak) occurs. As an enhancement to the Corrective Action Program element, RNP will revise the site procedure before entering into the period of extended operation to state that a condition report "shall" be initiated in accordance with Corrective Action Program procedures for throughwall failures, or when actual thickness is found to be substantially less than the expected value. Use of the term "administrative controls" in this statement was not meant to imply that the program enhancement was for the *Administrative Controls* program element.

In its response to RAI B.3.3-3b, the applicant stated that the "certain acceptance criteria" refer to FAC-related failures, including throughwall failures, or when actual wall thickness is found to be substantially less than the expected value.

The staff finds the applicant's response to RAI B.3.3-3 acceptable because the applicant has clarified the administrative controls and corrective actions in the Flow-Accelerate Corrosion Program, and these two program attributes are consistent with GALL XI.M17.

In RAI B.3.3-4, the staff asked the applicant to describe the condition reports relating to FAC. In its response to RAI B.3.3-4, the applicant stated that the as-found conditions and assessment results were documented and tracked within the Corrective Action Program using condition reports. The applicant's response to RAI B.3.3-1 applies to RAI B.3.3-4. The staff finds the applicant's response acceptable because the condition reports have been discussed in sufficient detail in the applicant's response to RAI B.3.3-1.

In RAI B.3.3-5, the staff asked the applicant to provide a list of the components in the Flow-Accelerated Corrosion Program that are most susceptible to FAC. The list should include initial wall thickness (nominal), current wall thickness, and the future predicted wall thickness. In its response to RAI B.3.3-5, the applicant stated that the goal of the Flow-Accelerated Corrosion Program is to eliminate the risk of piping failures (either leaks or minimum wall violations) caused by FAC. This requires that inspections identify the pipe, inspection data analysis supports accurate remaining life predictions, and uninspected pipe is modeled or analyzed to have high confidence in the predicted remaining life. Replacements are scheduled to preclude the need for reinspections.

The inspection selection process considers the predicted time to minimum acceptable wall thickness and predicted wear rates. Components with a short predicted service life are inspected first to confirm their suitability for continued service. For components previously inspected, the estimated time remaining to reach minimum acceptable wall thickness and wear rate may be obtained from actual inspection data. An initial population of components to be inspected is based on CHECWORKS model predictions, engineering judgment, and industry or plant events. Also included are components inspected as a result of sample expansion due to detected wear.

The applicant submitted a listing of the 100 most susceptible components subject to the RNP Flow-Accelerate Corrosion Program. The components are listed in order of lifetime average wear rate with run hours remaining to reach minimum wall thickness. In the listing, piping components are identified by line listings, followed by a unique number to identify the specific piping component (e.g., reducer, straight pipe, valve). Components which require "no further inspection" are those piping components with a predicted remaining life greater than plant life (including life extension).

The staff finds the applicant's response to RAI B.3.3-5 acceptable because the applicant has used the industry recognized software code, CHECWORKS, to predict pipe wall thinning and has analyzed appropriate piping systems. The applicant has shown that its Flow-Accelerated Corrosion Program has a systematic approach to predict component thickness, confirm the thickness by measurement, and schedule replacement if the component approaches minimum allowable thickness. The applicant's approach is consistent with GALL XI.M17.

In order to allow the staff to evaluate the accuracy of the FAC predictions, in RAI B.3.3-6, the staff asked the applicant to provide a few examples of the components for which wall thinning is predicted by the code and at the same time measured by ultrasonic examination or any other measurement method employed at RNP. This procedure would show the effectiveness of CHECWORKS in predicting the as-found condition.

In its response to RAI B.3.3-6, the applicant submitted a graph that compares predicted versus as-found thicknesses for RNP feedwater piping. The thickness prediction is based on initial thickness (nominal wall) minus the predicted wear over the life of the component. The predicted wear is calculated initially assuming no known wear. The wear is then adjusted based on actual measurements of many components within a pipe line. The adjustment is a correction factor which is applied to the predicted wear in the components in the line. Normally, some components will wear less than predicted and some will wear more than predicted. The line correction factor is derived by calculating an adjustment factor for each component, then taking the median value of these individual adjustments as the line correction factor. The actual thickness measurements vary from predictions due to variations in initial pipe wall thickness (e.g., some components are substantially thicker than nominal).

The applicant also submitted data sheets from several systems within the program scope.

These data sheets contain data points for measured thickness, predicted thickness, and minimum allowable thickness. The applicant's data showed that the majority of the measured pipe thickness values are greater than the predicted pipe thickness values which means that the applicant's prediction model is conservative. There are a few data points which showed that the predicted values are higher than the measured values; however, the measured pipe thickness of those data points are still within the minimum allowed pipe thickness.

The staff finds that the applicant's response to RAI B.3.3-6 is acceptable because the applicant has provided data to show that in most cases its prediction model is conservative. This is consistent with GALL XI.M17.

3.0.3.5.3 UFSAR Supplement

In Section A.3.1.11 of the LRA, the applicant provides a UFSAR Supplement summary for the Flow-Accelerated Corrosion Program. Program actions consist of (1) conducting appropriate analysis and baseline inspection, (2) determining the extent of thinning, (3) replacing/repairing components, and (4) performing followup inspections to confirm or quantify and take longer-term corrective actions as necessary. Originally, this program was prepared in response to NRC GL 89-08. The program relies on implementation of EPRI guidelines in NSAC-202L-R2. Prior to the period of extended operation, the Flow-Accelerated Corrosion Program will be modified to (1) include additional components potentially susceptible to FAC and/or erosion, and (2) specify corrective actions to be taken in accordance with the Corrective Action Program when certain acceptance criteria are not met.

The staff finds that the summary in the UFSAR Supplement is consistent with LRA Section B.3.3 and GALL XI.M17 and is, therefore, acceptable.

3.0.3.5.4 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.6 Bolting Integrity Program

3.0.3.6.1 Summary of Technical Information in the Application

The applicant described its Bolting Integrity Program in Section B.3.4 of Appendix B of the LRA. The LRA states that this program is consistent with GALL Program XI.M18, "Bolting Integrity," with exceptions regarding (1) the scope of bolting that credits this program, and (2) the inspection requirements and need for an ongoing program to monitor for cracking for high strength bolting used in NSSS component supports. The applicant stated that the Bolting Integrity Program is credited for aging management of bolting on mechanical components within the scope of license renewal.

The aging effects/mechanisms of concern specifically identified with regard to bolting integrity in applicable systems are (1) loss of material due to wear, loss of mechanical closure integrity due to Stress-Corrosion Cracking (SCC), loss of preload due to stress relaxation, and loss of mechanical closure integrity due to loss of material fromaggressive chemical attack (boric acid wastage).

The LRA states that the Bolting Integrity Program relies on other AMPs to manage specific aging effects. The Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Aging Management Program is credited with inspecting selected bolting within Section XI boundaries. In addition, the Preventive Maintenance Program performs regular inspections of RCP bolting. AMRs have credited the Boric Acid Corrosion Program for management of loss of mechanical closure integrity due to loss of material, which, in turn, is due to aggressive chemical attack (boric acid wastage) for mechanical system bolted closures subject to boric acid leakage. Otherwise, from the standpoint of loss of material due to general corrosion, bolting on mechanical components is treated as a subcomponent (i.e., a part of the parent component), and the Systems Monitoring Program is utilized to manage this aging effect. The ASME Section XI, Subsection IWF Program, is credited for aging management of all structural bolting associated with Class 1, 2, and 3 component supports, and the Structures Monitoring Program is credited for aging management of all structural bolting other than those associated with Class 1, 2, and 3 components.

As a result of the applicant's license renewal review, RNP has made some enhancements to the program administrative controls involving the program elements *Preventive Actions* and *Parameters Monitored/Inspected.* The Bolting Integrity Program implementation documents will be enhanced to prohibit the use of molybdenum disulfide compounds in high strength bolting applications. The program will also direct that high-strength bolting used on one motor operated valve be inspected and evaluated prior to the end of the current operating period, as part of the plant's Corrective Action Program.

Under "Operating Experience," the LRA states that the RNP implementation of NRC Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants," has been the subject of a number of NRC inspections. The applicant stated that an NRC Inspection Report dated May 1987 notes that reviews of the maintenance history and program for lubricating threaded fasteners had been completed in 1982 for RNP, and subsequent reviews were performed in 1983 and 1984 with no problems identified. The applicant also listed several bolting issues which have been addressed by the RNP Corrective

Action Program.

The applicant stated that although the Bolting Integrity Program is only credited at RNP for aging management of mechanical system bolting, both mechanical and structural bolting were reviewed to establish consistency with GALL Program XI.M18.

3.0.3.6.2 Staff Evaluation

In LRA Section B.3.4, "Bolting Integrity Program," the applicant described its program to manage aging of the bolting. The LRA states that this program is consistent with GALL Program XI.M18, "Bolting Integrity," with exceptions regarding (1) the scope of bolting that credits this program, and (2) the inspection requirements and need for an ongoing program to monitor for cracking for high strength bolting used in NSSS component supports. The staff confirmed the applicant's claim of consistency during the AMP audit. Furthermore, the staff reviewed the two deviations and their justification to determine whether the AMP, with the deviations, remains adequate to manage the aging effects for which it is credited. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program. In addition, the staff determined whether the applicant properly applied the GALL program to its facility.

The first exception to GALL relates to the scope of the program. The applicant stated that the Bolting Integrity Program is not utilized to address aging management requirements for structural bolting. The applicant stated that all structural bolting associated with Class 1, 2, and 3 component supports will be managed by the ASME Section XI, Subsection IWF Program, and all structural bolting other than those associated with Class 1, 2, and 3 components will be managed by the Structures Monitoring Program. The staff does not consider this to be an exception with respect to mechanical system closure bolting; therefore, the staff finds this acceptable.

The second exception relates to the aging management of high-strength bolting. GALL specifies that high strength bolting used in NSSS component supports be inspected to the requirements for Class 1 components, examination category B-G-1. The applicant took exception to these requirements because bolting in this application has been evaluated and is not susceptible to SCC due to its location in a benign environment. The applicant also took exception regarding the requirements for subjecting this bolting to an ongoing program for crack monitoring, for the same reason. In its April 28, 2003, response to the staff's RAI B.3.4-1, the applicant stated that there are only a few instances in which high strength bolting is used and these are in benign locations. The applicant also stated that there is only one instance where "hard" bolting is used for a pressure boundary, and the Bolting Integrity Program is used to manage this bolting, consistent with the GALL Report. The staff finds the above program exceptions to be acceptable on the basis that the bolting will not be susceptible to crack initiation and growth owing to the benign environment and low yield strength of the bolting.

As noted in LRA Section B.3.4, the RNP implementation of NRC Bulletin 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants," has been the subject of a number of NRC inspections. The applicant stated that an NRC inspection report dated May 1987 notes that reviews of the maintenance history and program for lubricating threaded fasteners had been completed in 1982 for RNP, and subsequent reviews performed in

1983 and 1984 did not identify any problems. The applicant also listed in Section B.3.4 several bolting issues which have been addressed by the RNP Corrective Action Program. Based on the information provided, the staff finds that the RNP operating experience supports the applicant's conclusion that the Bolting Integrity Program will adequately manage bolting.

3.0.3.6.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.7 Open-Cycle Cooling Water System Program

3.0.3.7.1 Summary of Technical Information in the Application

The applicant's Open-Cycle Cooling Water System Program is discussed in LRA Section B.3.5. The applicant states that it maintains a formal program at RNP identified as "Cooling Water Reliability Program (GL 89-13)," for oversight of the plant's commitments to GL 89-13 which corresponds to the Open-Cycle Cooling Water Program described in the LRA. The program's *Detection of Aging Effects* element will be enhanced by focusing on periodic replacement of cooling coils in certain room coolers under the site Preventive Maintenance Program. Furthermore, the applicant intends to perform a one-time volumetric examination of the component cooling water (CCW) heat exchangers prior to the end of the current license period under its One-Time Inspection Program to establish the frequency of inspections during the period of extended operation. The enhanced program will be consistent with GALL XI.M20, "Open-Cycle Cooling Water System."

This AMP is credited with managing the following aging effects in the selected components of the open-cycle cooling water system:

- flow blockage due to fouling
- loss of heat transfer effectiveness due to fouling of heat transfer surfaces
- loss of material due to crevice corrosion
- loss of material due to galvanic corrosion
- loss of material due to general corrosion
- loss of material due to microbiologically induced corrosion

- loss of material due to pitting corrosion
- loss of material due to erosion

The program has been the subject of a number of assessments by the applicant and inspections by the NRC since its inception. The inspections have focused on the CCW heat exchangers, the emergency diesel generator (EDG) heat exchangers and the safety injection (SI) pump bearing coolers. There has been no safety concern with the findings of the inspections.

3.0.3.7.2 Staff Evaluation

In LRA Section B.3.5, "Open-Cycle Cooling Water System Program," the applicant described its AMP to manage aging effects caused by erosion, corrosion, and biofouling. The LRA states that the applicant's enhancement to the program element *Detection of Aging Effects* will make the program consistent with GALL XI.M20 "Open-Cycle Cooling Water System."

Detection of Aging Effects: The LRA states that the program will be enhanced to initiate an action under the site's Preventive Maintenance Program to periodically replace cooling coils in certain room coolers. Also, a requirement to perform a one-time volumetric inspection of the CCW heat exchanger tubes prior to the end of the current period will be incorporated into the One-Time Inspection Program. Results from this inspection will be used to determine the need for inspection/testing over the period of extended operation.

The applicant states that the program is consistent with GALL XI.M20 "Open-Cycle Cooling Water System," with the above enhancement. The staff confirmed the applicant's claim of consistency during the AMP audit. The staff concludes that the applicant's program is consistent with the GALL program. There is no need, therefore, for the staff to review the attributes in the applicant's Open-Cycle Cooling Water System Program, with the exception of plant-specific operating experience. The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Operating Experience: The plant operating experience, described in the LRA, indicates that the guidance of GL 89-13 has been implemented for approximately 10 years and has been effective in managing aging effects due to biofouling, corrosion, erosion, protective coating failures, and silting in SCs serviced by open-cycle cooling water systems. The program has gone through a number of self-assessments and NRC inspections. There has been no safety concern with the findings of the inspections. The RNP program has been effective in managing the aging effects in those heat exchangers in the open-cycle cooling water system for which the GL 89-13 program is implemented. The staff, therefore, has determined that the applicant's program will adequately manage the aging effects in the components covered under Open-Cycle Cooling Water System Program during the period of extended operation.

3.0.3.7.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the

GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.8 Closed-Cycle Cooling Water System Program

3.0.3.8.1 Summary of Technical Information in the Application

The applicant's Closed-Cycle Cooling Water System Program is discussed in LRA Section B.2.5. The program is credited for aging management of selected components in the following systems at RNP:

- component cooling water system
- diesel generator system
- dedicated shutdown diesel generator system
- engineered safety features technical support center security diesel generator system

The applicant states that the program is consistent with GALL XI.M21 "Closed-Cycle Cooling Water System." This AMP is credited with managing the following aging effects in the selected components of the closed-cycle cooling water system:

- loss of material due to crevice corrosion
- loss of material due to galvanic corrosion
- loss of material due to general corrosion
- loss of heat transfer effectiveness due to fouling of heat transfer surfaces
- cracking due to stress-corrosion cracking
- loss of material due to pitting corrosion
- loss of material due to selective leaching

Under the program guidelines, chemistry is regularly monitored and maintained within standards in accordance with EPRI and/or manufacturers' recommendations. The applicant's operating experience identified wall-thinning due to erosion in CCW piping downstream of spent fuel pool heat exchangers. This condition was addressed by replacing the thinned piping and planning to implement periodic surveillance to monitor wall thickness in the future under the Preventive Maintenance Program. The applicant's subsequent self-assessment and review of operational performance of the CCW system have not revealed any safety concerns.

3.0.3.8.2 Staff Evaluation

In LRA Section B.2.5, "Closed-Cycle Cooling Water System Program," the applicant described its AMP to manage aging effects caused by erosion, corrosion, cracking, and selective leaching.

The applicant states that the program is consistent with GALL Program XI.M21 "Closed-Cycle Cooling Water System." The staff confirmed the applicant's claim of consistency during the AMP audit. The staff concludes that the applicant's program is consistent with the GALL program. There is no need, therefore, for the staff to review the attributes in the applicant's Closed-Cycle Cooling Water System Program, with the exception of plant-specific operating experience. The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Operating Experience: The applicant's operating experience identified wall-thinning due to erosion in CCW piping downstream of spent fuel pool heat exchangers. This condition was addressed by replacing the thinned piping and a plan to implement periodic surveillance to monitor wall thickness in the future under the Preventive Maintenance Program. The applicant's subsequent self-assessment and review of operational performance of the CCW system have not revealed any safety concerns. The staff, therefore, has determined that the applicant's program will adequately manage the aging effects in the components covered under the Closed-Cycle Cooling Water System Program during the period of extended operation.

3.0.3.8.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.9 One-Time Inspection Program

3.0.3.9.1 Summary of Technical Information in the Application

The applicant's One-Time Inspection Program is discussed in LRA Section B.4.4. The LRA states that the program is consistent with GALL XI.M32, "One-Time Inspection." The LRA states that the program was created to verify the effectiveness of existing AMPs, as well as to provide additional assurance that aging is not occurring or the aging is so insignificant that aging management is not required for the license renewal period. The AMP is credited for managing a variety of aging effects in various systems at RNP. The LRA states that the One-Time Inspection Program is a new program, and consequently does not identify specific operating experience.

3.0.3.9.2 Staff Evaluation

In LRA Section B.4.4, "One-Time Inspection Program," the applicant described its program to verify that certain aging effects do not require management during the license renewal period. The LRA stated that this AMP is consistent with GALL Program XI.M32, "One-Time Inspection," with no deviations. GALL recommends use of this program to verify the effectiveness of other AMPs. The staff confirmed the applicant's claim of consistency during the AMP audit. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program. Furthermore, the staff reviewed the applicant's evaluation to determine whether it addressed the additional issues recommended in the GALL Report and confirmed that the AMP would adequately address these issues. Finally, the staff determined whether the applicant properly applied the GALL program to its facility.

GALL recommends the use of this program to verify the effectiveness of the applicant's Water Chemistry Program (B.2.2), which is evaluated in Section 3.0.3.3 of this SER. The applicant uses the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program for the spent fuel, steam turbine, feedwater, condensate system, SG blowdown system, and auxiliary feedwater system. The SRP-LR states that a one-time inspection of select components at susceptible locations is an acceptable method to ensure that aging degradation is not occurring. The SRP-LR further states that selection of susceptible locations should be based on severity of conditions, time of service, and lowest design margin, and that the proposed inspections would be performed using appropriate techniques, including visual, ultrasonic, and surface techniques. The elements of the program include (1) determination of the sample size based on materials, environment, aging effects, and operating experience, (2) identification of inspection locations based on aging effect, and (3) identification of examination technique and acceptance criteria based on aging effect. In addition, the program elements state that the inspection includes a representative sample of the system population with, where practical, focus on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. These program attributes satisfy the recommendations in the SRP-LR for verifying the effectiveness of a chemistry program; therefore, the staff finds this acceptable.

GALL also recommends the use of this program, in conjunction with water chemistry, to verify that cracking is not occurring in small bore RCS and connected systems piping, where the ASME Code does not require volumetric examination during ISI. The LRA states that the One-Time Inspection Program will be used to verify that service-induced weld cracking is not occurring by checking a representative sample of piping. The LRA further states that the components to be examined will be selected based on accessibility, exposure levels, NDE techniques, and locations identified in (IN) 97-46; this statement is consistent with GALL. GALL XI.M32 states that, for small bore piping, including pipe, fittings, and branch connections, a plant-specific destructive examination of replaced piping (due to modifications) or NDE that permits inspection of the inside surfaces of the piping is to be conducted to ensure cracking is not occurring. These program attributes satisfy the recommendations in the SRP-LR for small bore RCS and connected systems piping; therefore, the staff finds this acceptable.

The staff has reviewed the UFSAR Supplement for this program and the applicant's April 28, 2003, response to RAI B.1-1. In its response to RAI B.1-1, the applicant committed to add the following statement for the One-Time Inspection Program, "This program is consistent with the corresponding program in the GALL Report." Since the GALL description of Program XI.M32 provides an appropriate description of the program, and includes a level of detail commensurate with the SRP-LR for the "further evaluation" for which the applicant credits this program, the staff finds that the UFSAR "Supplement, with the above statement, provides an adequate summary description of the activities for managing the effects of aging for the SCs that credit this program, as required by 10 CFR 54.21(d).

3.0.3.9.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.10 Selective Leaching of Materials Program

3.0.3.10.1 Summary of Technical Information in the Application

The applicant's Selective Leaching of Materials Program is discussed in LRA Section B.4.5, "Selective Leaching of Materials Program." The applicant stated that the program is consistent with GALL XI.M33, "Selective Leaching of Materials," with one exception that involves the use of mechanical means, other than Brinell hardness testing identified in the GALL Report, to identify the presence of selective leaching of material.

The AMP is credited for managing aging effects in various systems at RNP containing plant-specific components susceptible to the selective leaching mechanism. The aging effect/mechanism of concern is loss of material due to selective leaching. The program is credited for GALL and non-GALL items. These components are listed in Tables 3.2-2, 3.3-1, and 3.4-2 of the LRA and for the plant system groups engineering safety features, auxiliary systems, and steam and power conversion systems, respectively. These components are made from carbon steel and copper alloys. Selective leaching takes place when these components are exposed to raw water, treated water (including steam), or are buried underground. The applicant's Selective Leaching of Materials Program is a new program that involves a one-time inspection and mechanical test to be applied at RNP.

3.0.3.10.2 Staff Evaluation

In LRA Section B.4.5, "Selective Leaching of Materials Program," the applicant described its program to manage aging effects due to selective leaching. The LRA states that this AMP is consistent with GALL XI.M33, "Selective Leaching of Materials," with one exception that involves the use of mechanical means, other than Brinell hardness testing identified in the GALL Report, to identify the presence of selective leaching of material. The staff confirmed the applicant's claim of consistency during the AMP audit. Furthermore, the staff reviewed the deviation and its justification to determine whether the AMP, with the deviation, remains adequate to manage the aging effects for which it is credited, and reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program. In addition, the staff determined whether the applicant properly applied the GALL program to its facility.

With regard to the deviation related to the hardness testing, the applicant stated that the exception is justified because (1) hardness testing cannot be reliably performed for most components due to form and configuration, and (2) other mechanical means (i.e., resonance when struck by another object, scraping, or chipping) provide an equally valid method of identification. The staff considers the applicant's justification to be reasonable and acceptable.

The applicant provided its UFSAR Supplement for the Selective Leaching of Materials Program in Section A.3.1.32 of the LRA. The staff reviewed the UFSAR Supplement and finds that the summary description contains a sufficient level of information, as required by 10 CFR 54.21(d), and is acceptable.

3.0.3.10.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.11 Systems Monitoring Program

3.0.3.11.1 Summary of Technical Information in the Application

The applicant described its Systems Monitoring Program in Section B.3.17 of Appendix B of the LRA. The Systems Monitoring Program is credited for aging management of selected components in the various plant systems at RNP. The program consists of scheduled system walkdowns, system health reports, and performance monitoring of systems to manage the following aging effects/mechanisms:

- change in material properties due to various mechanisms
- cracking due to various mechanisms
- loss of material due to various mechanisms
- loss of heat transfer due to fouling
- loss of mechanical closure due to loss of material from aggressive chemical attack

The LRA states that the current systems monitoring procedures do not specifically describe the aging effects identified in the AMRs; therefore, the program will be enhanced to do the following

- include aging effects identified in the aging management reviews
- identify inspection criteria in checklist form
- include guidance for inspecting connected piping/components
- require documenting identified degradation and initiating appropriate corrective action(s)
- add a section specifically addressing corrective actions

Based on the above, the applicant concludes that the Systems Monitoring Program will provide reasonable assurance that the aging effects will be managed such that the components within the scope of license renewal will continue to perform their intended functions consistent with the CLB for the period of extended operation.

3.0.3.11.2 Staff Evaluation

In LRA Section B.3.17, "Systems Monitoring Program," the applicant described its program to manage aging of the various SCs within the scope of license renewal. The program is not based on a GALL program; therefore, the staff reviewed the program using the guidance in Branch Technical Position RLSB-1 in Appendix A of the SRP-LR. The staff's evaluation focused on management of aging effects through incorporation of the following 10 elements from RLSB-1— program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled Quality Assurance Program. The staff's evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER and the evaluation of the remaining seven elements is provided below. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

Program Scope: The LRA states that the program includes all maintenance rule systems and additional systems that encompass the "License Renewal" systems. The staff finds the scope of the program to be comprehensive and acceptable because it includes the SCs that credit this program.

Preventive or Mitigative Actions: The LRA states that the Systems Monitoring Program is a condition monitoring program and, thus, there are no preventive actions. The staff concurs with this assessment and does not identify the need for any preventive actions associated with this program.

Parameters Monitored or Inspected: The LRA states that the current procedures do not describe the aging effects identified in the AMRs. In its April 28, 2003, response to the staff's RAI B.3.17-1, the applicant stated that the parameters monitored or inspected are selected based on AMR results, including plant and industry operating experience, to ensure that aging degradation that could lead to loss of intended function will be identified and addressed. The applicant further stated that surface conditions of piping, ductwork, and various other mechanical system components, including closure bolting, are monitored/inspected through visual inspection and examination for evidence of defects and age-related degradation, including evidence of leaks. The applicant also stated that flexible connectors (i.e., vibration isolators) are monitored for cracking or other changes in material properties (including wear), and that air-cooled heat exchangers are monitored for fouling. The applicant also referred to the UFSAR Supplement that was provided with the LRA. The UFSAR Supplement commits to enhance the administrative controls to (1) include the aging effects identified in the AMR, (2) identify inspection criteria, and (3) include inspection guidance. The staff finds that the parameters monitored or inspected will provide symptomatic evidence of potential degradation and, therefore, are acceptable.

Detection of Aging Effects: The LRA states that the program relies on visual inspections of SCs during system walkdowns, and cover the accessible portions of the systems. In addition, the UFSAR Supplement provided in the LRA states that the enhancements to this program, to be completed before the period of extended operation, will identify inspection criteria and inspection guidance for the aging effects identified in the AMR. The staff finds that visual inspections of external surfaces of SCs, with the procedure enhancements described in the UFSAR Supplement, are acceptable for detecting the aging effects that are covered by this program.

Monitoring and Trending: The LRA states that the program activities provide for monitoring and trending of age-related degradation. The LRA further states that accessible portions of the systems are walked down at least once per quarter, that walkdowns are typically scheduled and performed such that there is a full walkdown of the entire system within one operating cycle, and that information from the walkdowns is trended and evaluated to identify and correct problems. The staff finds that the overall monitoring and trending proposed by the applicant is acceptable because it will effectively manage the applicable aging effects.

Acceptance Criteria: The LRA states that the program administrative controls will be enhanced to include visual monitoring acceptance criteria and guidelines for applying these criteria. In its April 28, 2003, response to the staff's request for additional information, the applicant further stated that existing procedures (with enhancements related to evaluating the extent of degradation and initiating corrective actions) include detailed guidance for inspecting and evaluating the material condition of SCs within the scope of this program, and that the guidance includes specific parameters to be monitored and criteria to be used for evaluating identified degradation. The staff finds that the use of the system checklists, described in the LRA, that include the above information will be acceptable for evaluating aging and initiating appropriate corrective actions; therefore, the staff finds this acceptable.

Operating Experience: The LRA states that the Systems Monitoring Program activities have provided an effective means of ensuring the system health for the systems subject to periodic walkdown, and that the processes at RNP are continually being upgraded based on industry experience. The staff finds that the applicant's operating experience supports the conclusion that the program will adequately manage the aging effects in the SCs that credit this program.

3.0.3.11.3 Conclusions

On the basis of its review of the applicant's program, the staff finds that the program adequately addresses the 10 program elements defined in Branch Technical Position (BTS) RLSB-1 in Appendix A.1 of the SRP-LR, and that the program will adequately manage the aging effects for which it is credited so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 50.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.3.12 Preventive Maintenance Program

3.0.3.12.1 Summary of Technical Information in the Application

The applicant described its Preventive Maintenance Program in Section B.3.18 of Appendix B of the LRA. The Preventive Maintenance Program is credited for aging management of selected components in the various plant systems at RNP. The purpose of the Preventive Maintenance Program is to prevent or minimize equipment breakdown and to maintain equipment in a satisfactory condition for normal and/or emergency use. The program consists of periodic component replacement, inspections, and tests to manage the following aging effects/mechanisms:

- change in material properties due to various mechanisms
- cracking due to various mechanisms
- loss of material due to various mechanisms
- loss of bolting preload due to stress relaxation
- reduced insulation resistance (IR) due to thermal embrittlement
- loss of heat transfer due to fouling

The applicant stated that the purpose of the Preventive Maintenance Program is to assure that various aging effects are managed for a wide range of components.

The activities performed under the Preventive Maintenance Program can be described in the general categories of component inspections for degradation such as loss of material, cracking and change in material properties, monitoring filter differential pressure, purging water from air receivers, checking bolt tension for loss of preload, checking for pressure boundary leakage in valves, piping and fittings, visual inspection and monitoring of cables and connections for loss of coating on cable trays or loss of insulation. The program administrative controls reference activities for monitoring structures, systems, and components to permit early detection of degradation. Data from walkdowns are trended and evaluated to identify and correct problems. In addition, the program includes periodic refurbishment or replacement of components.

3.0.3.12.2 Staff Evaluation

In LRA Section B.3.18, "Preventive Maintenance Program," the applicant described it program to manage aging of the various structures and components within the scope of license renewal. The program is not based on a GALL program; therefore, the staff reviewed the program using the guidance in Branch Technical Position RLSB-1 in Appendix A of the SRP-LR. The staff's evaluation focused on management of aging effects through incorporation of the following 10 elements from RLSB-1— program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled Quality Assurance Program. The staff's evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER and the evaluation of the remaining seven elements is provided below. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate
description of the program.

Program Scope: The LRA states that the program provides for periodic inspection and testing of components in various systems and structures. In its April 28, 2003, response to staff's RAI B.3.18-2, the applicant provided a summary of activities in various systems and components that are credited for management of specific aging effects, along with any planned enhancement. In particular, the program provides for periodic component replacement/refurbishment, inspection, and testing of components in the following systems and structures:

- reactor coolant system
- steam generator
- feedwater system
- auxiliary feedwater
- condensate system
- service water system
- component/closed cooling water system
- diesel generator system
- dedicated shutdown diesel generator
- fuel oil system
- EOF/TSC security emergency diesel generator
- instrument air system
- site fire protection system
- EDG cardox system
- fire protection CO_2 system

- halon supply system
- potable water system
- liquid waste processing system and isolation valve seal water system
- HVAC containment building system
- HVAC auxiliary building
- HVAC control room area
- reactor auxiliary Building
- various electrical systems
- primary and Demineralized Water System

Based on its review of the AMR tables in Section 3 of the LRA, the staff finds the scope of the program to be comprehensive and acceptable because it includes the structures and components that credit this program.

Preventive Actions: The LRA states that the Preventive Maintenance Program includes periodic refurbishment or replacement of components, which could be considered to be preventive or mitigative actions. The staff agrees that routine replacement or timely refurbishment of components will prevent or minimize equipment aging and will maintain equipment in a condition that will enable it to perform its intended function during the period of extended operation.

Parameters Monitored or Inspected: The LRA states that inspection and testing activities performed under the program monitor parameters including surface condition, loss of material, presence of corrosion products, and signs of cracking. The staff finds that the parameters inspected or monitored provide symptomatic evidence of potential degradation for timely replacement of components to prevent equipment failure and, therefore, are acceptable.

Detection of Aging Effects: The LRA states that the preventive maintenance and surveillance testing activities provide for periodic component inspections and testing to detect the following aging effects and mechanisms:

- change in material properties
- loss of material
- cracking
- loss of preload in bolting due to stress relaxation
- fouling
- reduced insulation resistance

The LRA states that the extent and schedule of inspections and testing assure detection of component degradation prior to loss of their intended functions. It also states that established techniques such as visual inspection and other nondestructive examination are used. The staff finds that the techniques used to detect aging effects are consistent with accepted engineering practice and, therefore, satisfy this program element.

Monitoring and Trending: The LRA states that the preventive maintenance activities provide for monitoring and trending of age-related degradation. Inspection intervals are established such that they provide for timely detection of component degradation. Inspection intervals are dependent on the component material and environment and take into consideration industry and plant-specific operating experience and manufacturers' recommendations. The LRA states that the Preventive Maintenance Program includes provisions for monitoring and trending with the stated intent of identifying potential failures or degradation and making adjustments to ensure components remain capable of performing their functions. The Preventive Maintenance Program emphasizes reporting of equipment deficiencies by all station personnel on a Maintenance Work Request or via the corrective action program for effective trending of aging effects.

The staff finds that the overall monitoring and trending techniques proposed by the applicant are acceptable because the inspections, replacements, and sampling activities described by the applicant will effectively manage the applicable aging effects.

Acceptance Criteria: The LRA states that the Preventive Maintenance Program acceptance criteria are defined in the specific inspection and testing procedures. The LRA further states that they confirm component integrity by verifying the absence of the aging effect or by comparing applicable parameters to limits based on the applicable intended function(s) as established by the plant design basis.Becuase the plant design basis includes code-specified acceptance criteria for applicable systems, the staff finds this acceptable.

Operating Experience: The LRA states that the preventive maintenance activities have been in place at RNP Unit 2 since the plant began operation. The LRA further states that these activities have demonstrated a history of detecting damaged or degraded components and, thereby, requiring repair or replacement in accordance with the site corrective action process. The staff finds that the applicant's operating experience supports the conclusion that the program will adequately manage the aging effects in the specified systems, structures and components.

3.0.3.12.3 Conclusions

On the basis of its review of the applicant's program, the staff finds that the program adequately addresses the 10 program elements defined in Branch Technical Position (BTS) RLSB-1 in Appendix A.1 of the SRP-LR, and that the program will adequately manage the aging effects for which it is credited so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 50.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.0.4 RNP Quality Assurance Program Attributes Integral to Aging Management Programs

The NRC staff has reviewed LRA Appendix A, Section A.3.1, "Aging Management Programs and Activities" and Appendix B, Section B.1, "Aging Management Programs," in accordance with the requirements of 10 CFR 54.21(a)(3) and 10 CFR 54.21(d). The staff has evaluated the adequacy of certain aspects of the applicant's programs to manage the effects of aging. The particular aspects reviewed by the staff in this section encompass three Quality Assurance Program attributes, namely corrective actions, confirmation process, and administrative controls. These three attributes of the Quality Assurance Program are addressed for all of the applicant's AMPs.

The license renewal applicant is required to demonstrate that the effects of aging on structures and components that are subject to an AMR will be adequately managed to ensure that their intended functions will be maintained in a manner that is consistent with the CLB of the facility throughout the period of extended operation. To manage these effects, applicants have developed new, or revised existing, AMPs and applied those programs to the SSCs of interest. For each of these AMPs, the existing 10 CFR Part 50, Appendix B, Quality Assurance Program may be used to address the attributes of corrective actions, confirmation process, and administrative controls.

3.0.4.1 Summary of Technical Information in Application

Chapter 3.0, "Aging Management Review Results," of the LRA provides an AMR summary for each unique structure, component, or commodity group at RNP determined to require aging management during the period of extended operation. This summary includes identification of aging effects requiring management and AMPs utilized to manage these aging effects.

Appendix B, "Aging Management Programs," of the LRA provides the aging management activity description for each activity credited for managing aging effects. These activities are based upon the aging management review results provided in Sections 3.1 through 3.6 of the LRA. In Section B.1, the applicant stated that it uses the existing RNP Quality Assurance Program to address the elements of corrective action, confirmation process, and administrative controls for all of its AMPs. The RNP Quality Assurance Program implements the requirements of 10 CFR 50 Appendix B. The applicant further states that these programs, credited for license renewal, encompass both the safety-related and non-safety-related SCs that perform an intended function for license renewal.

New or enhanced aging management programs identified in Appendix B, Sections B.4 and B.3, of the LRA provide descriptions of the specific attributes of corrective action, confirmation process, and administrative controls. All other programs are existing and the applicant confirmed that they were consistent with the guidance in NUREG-1801.

3.0.4.2 Staff Evaluation

During the audit of the applicant's renewal scoping and screening process, the staff also examined the applicant's processes for addressing corrective action, confirmation processes, and document control (the quality assurance attributes) associated with the various aging management programs credited for managing the potential aging effects of SSCs over the period of extended operation of the plant. As part of the review, the audit team reviewed the aging management program calculations for each credited program, and discussed the applicant's approach for the incorporation of the quality assurance attributes with the cognizant engineering personnel. In addition to the AMPs originally listed in the LRA, the applicant added more AMPs as a result of LRA review process. The additional AMPs were also reviewed by the audit team and are included in the conclusions below.

The team observed that in each AMP calculation, the applicant created a matrix containing each of the 10 program attributes which identified the attribute, the corresponding GALL program description, a comparison of the site-specific program to with GALL, and a conclusion statement indicating consistency with GALL and any exceptions or enhancements, if applicable. With respect to the three quality assurance attributes, the audit team found that the applicant's evaluations identified programs and procedures consistent with the site quality assurance process to capture the required quality assurance activities.

The audit team did not observe any exceptions to the use of the site Appendix B Quality Assurance Program for the evaluation of the three quality assurance attributes. The applicant identified implementing procedures, including the site and corporate quality assurance manual, document control, and testing procedures, to govern the activities associated with the three quality assurance attributes. For each AMP where site-specific procedures are utilized in addition to the corporate QA guidance, those additional procedures are identified and actions to be taken in accordance with those procedures are described in general terms. The procedures referenced are all site-specific procedures that are developed and maintained in accordance with the applicant's Appendix B requirements for document preparation.

On the basis of the audit team's review of the applicant's AMP calculations with respect to the three quality assurance attributes of corrective actions, confirmation process, and administrative controls, the team determined that the activities specified in the applicant's AMPs are consistent with NUREG-1801, "The Generic Aging Lessons Learned" (GALL) documentation; NUREG-1800, "The Standard Review Plan for License Renewal"; Branch Technical Position IQMB-1, "Quality Assurance for Aging Management Programs"; and the requirements set forth in 10 CFR 54.4 and 54.21, respectively.

3.0.4.3 Conclusions

Based on the staff's review of the applicant's LRA descriptions regarding the AMP QA attributes credited for license renewal, and the results of the staff's audit of the scoping and screening methodology, the staff finds that the QA attributes described for all AMPs credited for license renewal are consistent with the requirements of 10 CFR 54.21(a)(3). With regard to the UFSAR Supplement, the applicant has provided an acceptable UFSAR Supplement describing the three program elements of corrective actions, confirmation process, and administrative controls. On this basis, the staff concludes that the applicant has provided an adequate description of the program attributes to satisfy 10 CFR 54.21(d).

3.1 Reactor Systems

This section addresses the aging management of the components of the RCS and its subsystems. The RCS subsystems are described in the following SER sections

- reactor coolant system piping (Section 2.3.1.1), including ASME Code Class 1 piping (Section 2.3.1.1.1) and reactor coolant system non-Class 1 piping (Section 2.3.1.1.2)

- reactor coolant pumps (Section 2.3.1.2)

- pressurizer (Section 2.3.1.3)
- reactor vessel (Section 2.3.1.4)
- reactor vessel internals (Section 2.3.1.5)
- steam generators (Section 2.3.1.6)

The applicant's AMR evaluations of the components in each of the six RCS subsystems are given in one of two LRA tables, LRA Tables 3.1-1 or 3.1-2.

The scope of AMR Items 18 through 35 of LRA Table 3.1-1 provides the AMR results which are consistent with GALL and for which GALL has concluded that no additional evaluation is necessary beyond that which is provided in the AMR entry for the component in the corresponding GALL evaluation table. The staff's evaluation of LRA Table 3.1-1, Items 18 through 35, is given in Section 3.1.2.1 of this SER. The scope of AMR Items 1 through 17 of LRA Table 3.1-1 provides the AMR results which are consistent with GALL and for which the corresponding AMR analysis in the GALL evaluation table has concluded are in need of additional evaluation. The staff's evaluation of LRA Table 3.1-1, Items 1 through 17, is given in Section 3.1.2.2 of this SER.

The scope of LRA Table 3.1-2 consists of the AMR results for RCS system components that are not evaluated in the GALL report, or for which the corresponding AMR results are not in agreement with the corresponding AMR results for these components in GALL. The staff's evaluation of the AMRs for these components can be found in Section 3.1.2.4 of this SER.

The staff's evaluations of the AMPs that are specific to the RCS at RNP are given in the following subsections to Section 3.1.2.3 of this SER.

- Reactor Head Closure Studs Program (SER Section 3.1.2.3.1)
- Nickel-Alloy Nozzles and Penetrations Program (SER Section 3.1.2.3.2)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (SER Section 3.1.2.3.3)
- PWR Vessel Internal Program (SER Section 3.1.2.3.4)
- Steam Generator Tube Integrity Program (SER Section 3.1.2.3.5)
- Reactor Vessel Surveillance Program (SER Section 3.1.2.3.6)
- Flux Thimble Eddy Current Inspection Program (SER Section 3.1.2.3.7)

3.1.1 Summary of Technical Information in the Application

In LRA Section 3.1, the applicant described its AMRs for the RCS subsystems at RNP. The applicant provided its AMR results for the passive, long-lived components in the RCS subsystems in LRA Tables 3.1-1 and 3.1-2. These AMRs included an evaluation of plant-specific and industry operating experience. The scope of the applicant's operating experience review for the RCS components included the following experience.

- site specific experience—RNP site-specific operating experience was reviewed, including
(1) the Corrective Action Program, (2) Licensee Event Reports, (3) the Maintenance Rule Data Base, and (4) interviews with systems engineers.

- industry experience—An evaluation of industry operating experience published since the effective date of the GALL Report was performed to identify any additional aging effects requiring management.

- ongoing experience—ongoing review of plant-specific and industry operating experience is performed in accordance with the Corrective Action and Operating Experience Programs.

In the LRA, the applicant reviewed operating experience through December 2001. The applicant stated that operating experience subsequent to December 2001 will be reviewed; applicable operating experience will be updated in conjunction with the amendment to the application required by 10 CFR 54.21(b). The results of the applicant's operating experience reviews concluded that the aging effects requiring management based on industry operating experience were consistent with the aging effects identified in GALL.

3.1.2 Staff Evaluation

In Section 3.1 of the LRA, the applicant describes its AMRs for the RCS components at RNP. The staff reviewed Section 3.1 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation, in accordance with the requirements of 10 CFR 54.21(a)(3), for the RCS components determined to be within the scope of license renewal and subject to an AMR.

Table 3.1-1 below provides a summary of the staff's evaluation of the aging effects and AMPs for the components of the RCS subsystems that are discussed in LRA Section 3.1, evaluated by the applicant in Table 3.1-1 of the LRA, and addressed by the staff in the GALL Report.

Table 3.1-1
Staff Evaluation Table for RNP Reactor System Components in the GALL Report

GALL Component Group Description (Corresponding LRA Table and AMR No.)	Aging Effect/Aging Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation (SER Section)

RCPB components (Table 3.1-1, AMR 1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA for Thermal Fatigue (Section 4.3 of the LRA)	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.1)
SG shell assembly (Table 3.1-1, AMR 2)	Loss of material due to pitting and crevice corrosion	Inservice Inspection; Water Chemistry	ASME ISI[1] Water Chemistry Program	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.2)
Pressure vessel ferritic materials that have a neutron fluence greater than 10^{17} n/cm^2 (E>1 MeV) (Table 3.1-1, AMR 3)	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, evaluated in accordance with Appendix G of 10 CFR 50 and RG 1.99, Rev. 2	TLAAs for neutron irradiation embrittlement (Section 4.2 of the LRA)	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.3)
RV beltline shell and welds (Table 3.1-1, AMR 4)	Loss of fracture toughness due to neutron irradiation embrittlement	Reactor Vessel Surveillance	Reactor Vessel Surveillance Program	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.3)
Westinghouse and B&W baffle/former bolts (Table 3.1-1, AMR 5)	Loss of fracture toughness due to neutron irradiation embrittlement and void swelling	Plant-specific	PWR Vessel Internals Program	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.3)
Small bore RCS and connected systems piping (Table 3.1-1, AMR 6)	Crack initiation and growth due to SCC, IGSCC, and thermal and mechanical loading	Inservice Inspection; Water Chemistry; One-Time Inspection	Water Chemistry Program, ASME XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.4)
Vessel shell (Table 3.1-1, AMR 7)	Crack growth due to cyclic loading	TLAA	TLAA for evaluating underclad cracking (Section 4.3.4 of the LRA)	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.5)
Reactor internals (Table 3.1-1, AMR 8)	Changes in dimension due to void swelling	Plant-specific	PWR Vessel Internals Program	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.6)
PWR core support pads, instrument tubes (bottom head penetrations), pressurizer spray heads and nozzles for the SG instruments and drains (Table 3.1-1, AMR 9)	Crack initiation and growth due to SCC and/or PWSCC	Plant-specific	Water Chemistry Program and ASME XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program	Partially consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.7)

[1]The official title of the ASME ISI Program in the license renewal application for the H.B. Robinson Nuclear Power Plant is the ASME Section XI, Subsection IWB, IWC, and IWD Program.

Alternate AMR entries for core support pads and RV bottom VHP nozzles are provided in AMRs 9 and 10 of LRA Table 3.1-2, which are evaluated in Sections 3.1.2.4.4.2 and 3.1.2.4.4.3 of this SER, respectively; CASS RCS piping (Table 3.1-1, AMR 10)	Crack initiation and growth due to SCC	Plant-specific	Water Chemistry Program	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.7)
Pressurizer instrumentation penetrations and heater sheaths and sleeves made of nickel alloys. (Table 3.1-1, AMR 11)	Crack initiation and growth due to PWSCC	Inservice Inspection; Water Chemistry	Water Chemistry and ASME XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program apply even though the corresponding components at RNP are made out of stainless steel	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.7)
Westinghouse and B&W baffle/former bolts (Table 3.1-1, AMR 12)	Crack initiation and growth due to SCC and IASCC	Plant-specific	PWR Vessel Internals Program and Water Chemistry Program	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.8)
Westinghouse and B&W baffle/former bolts (Table 3.1-1, AMR 13)	Loss of preload due to stress relaxation	Plant-specific	ASME XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program and PWR Vessel Internals Program	Consistent with GALL. GALL recommends further evaluation (Section 3.1.2.2.9)
SG feedwater impingement plate and support (Table 3.1-1, AMR 14)	Loss of section thickness due to erosion	Plant-specific	Discussion section indicates that this GALL AMR is not applicable to RNP because RNP uses feed rings with J-nozzles for the corresponding component design	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.10)
SG tubes, repair sleeves, and plugs made from Alloy 600 (Table 3.1-1, AMR 15)	Crack initiation and growth due to PWSCC, ODSCC, and/or IGA or loss of material due to wastage and pitting corrosion and fretting and wear; or deformation due to corrosion at tube support plate intersections	Steam Generator Tubing Integrity; Water Chemistry	Steam Generator Tube Integrity Program and Water Chemistry Program	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.11)

Tube support lattice bars made of carbon steel (Table 3.1-1, AMR 16)	Loss of section thickness due to FAC	Plant-specific	RNP indicates that the GALL AMR for these components is only applicable to CE designs but states AMR 21 of LRA Table 3.1-1 identifies the SG components susceptible to FAC	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.12)
Carbon steel tube support plate (Table 3.1-1, AMR 17)	Ligament cracking due to corrosion	Plant-specific	Steam Generator Tube Integrity Program and Water Chemistry Program	Consistent with GALL. GALL recommends further evaluation. (Section 3.1.2.2.13)
SG feedwater inlet ring and supports (No corresponding LRA Table and AMR Item; however, this GALL Item is assessed in Section 3.1.2.2.14 of this SER)	Loss of material due to flow corrosion	CE steam generator feedwater ring inspection	N/A – LRA Table 3.1-1 does not include a corresponding AMR because GALL Volume 1 states that this AMR is applicable only to CE designs; however, this GALL Item is assessed in Section 3.1.2.2.14 of this SER	Consistent with GALL. GALL recommends further evaluation. (The staff evaluates this AMR as applicable to the RNP design in Section 3.1.2.2.14)
Reactor vessel closure studs and stud assembly (Table 3.1-1, AMR 18)	Crack initiation and growth due to SCC and/or IGSCC	Reactor Head Closure Studs	Reactor Head Closure Studs Program	Consistent with GALL. (Section 3.1.2.1)
3.1.2.1)Pump casings and valve bodies made from CASS (Table 3.1-1, AMR 19)	Loss of fracture toughness due to thermal aging embrittlement	Inservice Inspection	ASME XI, Inservice Inspection, Subsection IWB, IWC, and IWD Program and evaluation performed per Thermal Aging Embrittement of Cast Austenitic Stainless Steel (CASS) Program	Consistent with GALL. (Section 3.1.2.1)
CASS piping (Table 3.1-1, AMR 20)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	Thermal Aging Embrittlement of CASS Program and ASME XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program	Consistent with GALL. (Section 3.1.2.1)
BWR piping and fittings; SG components (Table 3.1-1, AMR 21)	Wall thinning due to FAC	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion Program	Consistent with GALL. (Section 3.1.2.1)
RCPB valve closure bolting, manway and holding bolting, and closure bolting in high pressure and high temperature systems (Table 3.1-1, AMR 22)	Loss of material due to wear; loss of preload due to stress relaxation; crack initiation and growth due to cyclic loading and/or SCC	Bolting Integrity	Bolting Integrity Program with the exception that the Reactor Head Closure Studs Program is used for the RV studs	Partially consistent with GALL. (Section 3.1.2.1) Alternate AMR entry for the SG primary and secondary manway bolts is given in AMR 12 of LRA Table 3.1-2, which is assessed in Section 3.1.2.4.6.8 of this SER.
CRD nozzle (Table 3.1-1, AMR 23)	Crack initiation and growth due to PWSCC	Nickel-Alloy Nozzles and Penetrations; Water Chemistry	Nickel-Alloy Nozzle and Penetrations Program	Consistent with GALL. (Section 3.1.2.1)

Reactor vessel nozzles safe ends and CRD housing; RCS (except CASS and bolting) (Table 3.1-1, AMR 24)	Crack initiation and growth due to cyclic loading, and/or SCC and PWSCC	Inservice Inspection; Water Chemistry	Water Chemistry Program; ASME XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program	Consistent with GALL. (Section 3.1.2.1)
RV internals components made from CASS (Table 3.1-1, AMR 25)	Loss of fracture toughness due to thermal aging, neutron irradiation embrittlement, and void swelling	Thermal aging and neutron irradiation embrittlement	PWR Vessel Internals Program	Partially consistent with GALL. (Section 3.1.2.1) Alternate AMR entry justifying use of the PWR Vessel Internals Program for aging management is given in AMR 14 of LRA Table 3.1-2, which is evaluated in Section 3.1.2.4.5.3 of this SER.
External surfaces of carbon steel components in RCS pressure boundary (Table 3.1-1, AMR 26)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	Boric Acid Corrosion Program and ASME XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program	Consistent with GALL. (Section 3.1.2.1)
SG secondary manways and handholes (Table 3.1-1, AMR 27)	Loss of material due to erosion	Inservice Inspection	N/A – Corresponding AMR in Table 3.1-1 states the AMR is only applicable to once-through SGs	Consistent with GALL. (Section 3.1.2.1)
RV internals, RV closure studs, and core support pads (Table 3.1-1, AMR 28)	Loss of material due to wear	Inservice Inspection	Reactor Vessel Head Closure Studs Program for RV studs; Flux Thimble Tube Eddy Current Program for flux thimble tubes; and ASME XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program for wear in RV internal components	Consistent with GALL. (Section 3.1.2.1)
Pressurizer integral support (Table 3.1-1, AMR 29)	Crack initiation and growth due to cyclic loading	Inservice Inspection, loose parts monitoring, and/or neutron noise monitoring	ASME XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program	Consistent with GALL. (Section 3.1.2.1)
Westinghouse upper and lower internal assemblies (Table 3.1-1, AMR 30)	Loss of preload due to stress relaxation	Inservice Inspection; loose part and/or neutron noise monitoring	PWR Vessel Internals Program and ASME XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program.	Partially consistent with GALL. (Section 3.1.2.1) Alternate AMR entry for justifying use of the PWR Vessel Internals Program for aging management is given in Item 15 of LRA Table 3.1-2, which is evaluated in Section 3.1.2.4.5.4 of this SER
RV internals in fuel zone region, with the exception of B&W and Westinghouse baffle bolts (Table 3.1-1, AMR 31)	Loss of fracture toughness due to neutron irradiation embrittlement and void swelling	PWR Vessel Internals; Water Chemistry	PWR Vessel Internals Program; Water Chemistry Program	Consistent with GALL. (Section 3.1.2.1)

SG upper and lower heads; tubesheets; primary nozzles and safe-ends (Table 3.1-1, AMR 32)	Crack initiation and growth due to SCC, PWSCC, and/or IASCC	Inservice Inspection; Water Chemistry	ASME XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program; Water Chemistry Program	Consistent with GALL (Section 3.1.2.1)
RV internals, with the exception of B&W and Westinghouse baffle/ former bolts (Table 3.1-1, AMR 33)	Crack initiation and growth due to SCC and IASCC	PWR Vessel Internals; Water Chemistry	PWR Vessel Internals Program; Water Chemistry Program	Consistent with GALL (Section 3.1.2.1)
RV closure studs and stud assembly (Table 3.1-1, AMR 34)	Loss of material due to wear	Reactor Head Closure Studs	Reactor Head Closure Studs Program	Consistent with GALL (Section 3.1.2.1)
RV internals—Westinghouse upper and lower internal assemblies and CE bolts and tie rods (Table 3.1-1, AMR 35)	Loss of preload due to stress relaxation	Inservice Inspection; Loose Part Monitoring	PWR Vessel Internals Program and ASME XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program	Partially consistent with GALL. (Section 3.1.2.1) Alternate AMR justifying the PWR Vessel Internals Program and ASME ISI Program as alternative AMPs for aging management is provided in Item 15 of LRA Table 3.1-2 which is evaluated in Section 3.1.2.4.5.4 of this SER

3.1.2.1 Aging Management Evaluations in the GALL Report That Are Relied On for License Renewal, and Which Do Not Require Further Evaluation

For component groups evaluated in GALL for which the applicant has claimed consistency with GALL, and for which GALL does not recommend further evaluation, the staff evaluated the AMRs given in Items 18-35 of LRA Table 3.1-1 against the AMRs in the staff's corresponding commodity group items of GALL Section IV, Volume 2, in order to determine whether the applicant's AMRs were consistent with or more conservative than those evaluated in the GALL Report. The staff assessments of the specific AMRs given in AMR Items 18-35 of LRA Table 3.1-1 are discussed in the subsections that follow.

The applicant provided its AMRs for its commodity group components that the applicant had claimed are consistent with GALL, but for which the SRP-LR and GALL recommend further evaluation in AMR Items 1–17 of Table 3.1-1 of the LRA. These AMRs correspond to the AMRs that are listed and defined in rows 1–17 of Table 3.1-1 of this SER. The staff evaluates these AMRs in Sections 3.1.2.2.1 through 3.1.2.2.13 of this SER. In addition, as part of its review, the staff concluded that loss of material in the SG feedwater inlet ring and supports could be another AMR that should be given additional analysis. This additional AMR corresponds to the AMR that is defined in row 18 in Table 3.1-1 of this SER. The staff evaluates this additional AMR item in Section 3.1.2.2.14 of this SER. Section 3.1.2.2.15 provides the staff's general conclusions for Section 3.1.2.2 of the SER.

Item 18—RV studs and stud assembly—crack initiation and growth by SCC and/or IGSCC - corresponding GALL-2 entry for Westinghouse-designed PWRs is IV.A2.1-c

The scope of AMR Item 18 of LRA Table 3.1-1 (page 3.1-18 of the LRA) evaluates the potential for SCC/intergranular stress-corrosion cracking (IGSCC) to occur in the RV studs and stud assembly. Carolina Power and Light Company (CP&L) states that SCC is not an applicable effect for Alloy 4140 steels (i.e., quenched and tempered low-alloy steel conforming to Specification SA 193 for Grade B7 steels) because the minimum yield strength for the materials is less than 150 kilograms per square inch (ksi). Minimum yield strength is not a material property but rather an acceptance criterion in ASME Material Specification SA-193 that must be met for SA-193, Grade B7 steels used for bolting components. For these materials, SA-193 specifies 105 ksi as the minimum yield strength to which SA-193, Grade B7 materials must conform. In the staff's generic SER on WCAP-14574 for license renewal of PWR pressurizer components, dated August 7, 2000 (ADAMS Accession Number ML003738981), the staff concluded that SCC in these materials may be minimized if yield strengths for the bolts were held to less than 150 ksi or if hardness for the bolts were maintained to less that 32 on a Rockwell C hardness scale. Therefore, in the generic SER, the staff stated that an applicant for license renewal may conclude that SCC is not an applicable effect for SA-193, Grade B7 steels used in bolting components if the applicant could demonstrate that the yield strengths for the bolting components were controlled to less than 150 ksi or if the hardness for the bolts were controlled to less than 32 on a Rockwell C hardness scale.

In RAI 3.1.2.1-1, the staff requested confirmation that the intent of the discussion section for Item 18 of Table 3.1-1 of the LRA is to state that CP&L has confirmed that the yield strengths for the RV bolts are within the 105–150 ksi range. In the RAI, the staff informed the applicant that if this were the intent of the discussion section, AMR Item 18 of LRA Table 3.1-1 is consistent with GALL.

In its response to RAI 3.1.2.1-1, the applicant stated that the RV head closure studs are made from SA 540, Grade B23 or B24 bolting materials and clarified that AMR Item 18 of Table 3.1-1 has been updated to identify cracking as an applicable aging effect for the RV closure studs. The applicant also stated that it will use the Reactor Head Closure Studs Program to manage cracking that may occur in the RV closure studs. This response is consistent with GALL commodity group item IV.A2.1-c and is therefore acceptable

Item 19—RCS CASS pump casings and valve bodies—loss of fracture toughness due to thermal aging—corresponding GALL-2 entries are IV.C2.3-c and IV.C2.4-c.

The scope of AMR Item 19 of LRA Table 3.1-1 (page 3.1-19 of the LRA) evaluates the effect of thermal aging on the fracture toughness properties of RCS pump casings and valve bodies made from (CASS). In its review of AMR Item 19 of LRA 3.1-1, the staff determined that the description in the discussion section of the AMR was consistent with guidance provided in AMR Items IV.C2.3-c and IV.C2.4-c of GALL, Volume 2, and is therefore acceptable.

Item 20—RCS CASS piping—loss of fracture toughness due to thermal aging—corresponding GALL—2 entries are IVC2.1-f; IV.C2.2-e, and IV.C2.5-l.

The scope of AMR Item 20 of LRA Table 3.1-1 (page 3.1-20 of the LRA) evaluates loss of fracture toughness due to thermal aging in RCS piping components made from CASS. In its review of AMR Item 20 of LRA 3.1-1, the staff determined that the description in the discussion section of the AMR was consistent with guidance provided in AMR Items IVC2.1-f, IV.C2.2-e, and IV.C2.5-l of GALL, Volume 2, and is therefore acceptable. The results of the staff's evaluation of the effect of thermal aging on the leak-before-break analysis for the RCS piping are given in Section 4.6.1 of this SER.

Item 21—Steam generator components susceptible to FAC—corresponding GALL-2 entries are IV.D1.1-d, IV.D1.2-h, IV.D1.3-a

The scope of AMR Item 21 of LRA Table 3.1-1 (page 3.1-20 of the LRA) evaluates SG components that are susceptible to FAC. For recirculating SGs, the SG commodity groups susceptible to FAC are covered by the scope of the AMRs for commodity group Items IV.D1.1-d (pressure boundary and structural SG commodity groups), IV.D1.2-h (SG tube bundle commodity group), and IV.D1.3-a (upper SG assembly and separators commodity group) of GALL, Volume 2, and include GALL components IV.D1.1.2, "steam nozzle and safe-end"; IV.D1.1.5, "feedwater nozzle and safe-end"; IV.D1.2.2, "SG tube support lattice bars"; and IV.D1.3.1, "feedwater inlet ring and support."

In RAI 3.1.2.1-2, the staff requested clarification of the exact SG components that are covered within the scope of AMR Item 21 of Table 3.1-1 and are susceptible to FAC, and a technical basis as to why the AMR for the components within the scope of AMR Item 21 was considered to be consistent with the AMRs for commodity group Items IV.D1.1-d, IV.D1.2-h, and IV.D1.3-a of GALL, Volume 2.

In its response to RAI 3.1.2.1-2, dated April 28, 2003, the applicant stated that, as noted in LRA Table 3.1-1, Item 16, the subcomponents of the SG that are part of LRA Table 3.1-1, Item 21, include the steam nozzle and the feedwater nozzle and its associated SG feedwater nozzle thermal sleeve. As can be seen in GALL, page IV.D1-10, Item D1.2.2, tube support lattice bars are part of a Combustion Engineering (CE) design and are not applicable to RNP because RNP is a Westinghouse NSSS plant. Also, GALL Item IV.D1.3.1, feedwater inlet ring and support," has no license renewal intended function and is therefore not in scope. The staff finds the applicant's response to RAI 3.1.2.1-2 acceptable because the applicant provided the SG components that are susceptible to FAC. Therefore, for the in-scope components, Item 21 of LRA Table 3.1-1 is consistent with GALL.

Item 22—Loss of material due to wear, crack initiation and growth (fatigue/SCC), and loss of preload in RCS bolting other than the RV closure studs and stud assembly—corresponding GALL-2 entries are IV.A2.2-e, IV.A2.2-f, IV.A2.2-g, IV.C2.3-d, IV.C2.3-e, IV.C2.3-g, IV.C2.4-d, IV.C2.4-e, IV.C2.4-g, IV.C2.5-n, IV.C2.5-p, IV.D1.1-f, and IV.D1.1-l

In AMR Item 22 of LRA Table 3.1-1 (pages 3.1-21 and 3.1-22 of the LRA), the applicant evaluates whether or not loss of material due to wear, crack initiation and growth due to fatigue or SCC, and loss of preload due to stress relaxation are applicable aging effects for RCS bolting other than that used to secure the RV stud assembly (i.e., except for the RV closure studs). The staff's evaluation of the applicant's AMR analyses for the RCS bolting, other than that used to secure the RV stud assembly, is given in the italicized subsection titles that follow. The staff's specific evaluation of the aging effects for the bolts used to secure the SG and secondary manway and handholes is given in the last italicized subsection title for this AMR item.

Aging of RCS bolting materials other than the RV closure head studs and the SG primary and secondary manway and handhole bolts—management of loss of material due to wear

The staff's AMR evaluations for GALL commodity group item IV.A2.2-f identifies that loss material due to wear is an applicable aging effect for control rod drive (CRD) head penetration flange bolting (GALL component A2.2.3). In AMR Item 22 of LRA Table 3.1-1, the applicant concludes that, with the exception of the bolts used to secure the primary and secondary manways in the SGs, loss of material due to wear is an applicable aging effect for all RCS Class 1 bolting components and RCS Class 2 bolting components greater than 2 inches in diameter. The applicant has expanded the applicability of this aging effect to all components within the scope of AMR 22 to LRA Table 3.1-1, other than the SG primary and secondary manway and handhole bolting. The assessment in AMR Item 22 of LRA Table 3.1-1, which evaluates loss of material due to wear, applies to more RCS bolting components than are identified in Section IV of GALL, Volume 2, and is therefore more conservative than GALL and is acceptable. The applicant credits the Bolting Integrity Program for managing wear in these components. This is consistent with the AMP credited in the AMR analysis for GALL commodity group item IV.A2.2-f and is also acceptable.

Aging of RCS bolting materials other than the RV closure head studs and the SG primary and secondary manway and handhole bolts—Management of crack initiation and growth due to SCC

The staff's AMR evaluations for GALL commodity group items IV.A2.2-e, IV.C2.3-e, IV.C2.4-e, IV.C2.5-n, and IV.D1.1-l identify the crack initiation and growth due to SCC as an applicable effect for control rod drive mechanism (CRDM) flange bolts (GALL component IV.A2.2.3), RCP bolts (GALL component IV.C2.3.3), RCS valve bolting (GALL component IV.C2.4.3), pressurizer manway and flange bolting (GALL component IV.C2.5.9), and SG primary manway bolting (GALL component IV.D1.1.11). In AMR Item 22 of LRA Table 3.1-1, the applicant stated that SCC is not an applicable aging effect that needs to be managed for the bolting material in the RCS because the applicant controls the yield strengths for the procured bolting materials to less than 150 ksi. This is a deviation from the corresponding AMR evaluations in Section IV of GALL, Volume 2. The staff evaluates this deviation from GALL in the following paragraph.

The staff has used 150 ksi as the threshold for initiation of SCC in high-strength bolting materials (i.e., quenched and tempered low-alloy steel grades, martensitic stainless steel grades or precipitation hardened stainless steel grades). The staff considers that SCC will not be an applicable aging effect for high-strength martensitic or precipitation hardened stainless steel bolting materials if the yield strengths for the procured materials are below 150 ksi or if the hardness values for the procured materials are less than a value of 32 on a Rockwell C hardness scale. SA 193, Grade B7 steel is an example of a material to which this criterion has been applied. The staff concurs that SCC will not be applicable if the yield strengths cited in the procurement documents for martensitic or precipitation hardened stainless steel bolts are less than 150 ksi. However, the staff has not used the 150 ksi criterion as a basis for concluding that SCC is not applicable to carbon steel bolting materials. The staff is seeking confirmation whether or not there is any plant-specific or generic industry experience that supports the conclusion that crack initiation and growth due to SCC is an applicable aging effect for carbon steel bolting materials in the RCS. If industry experience does support that crack initiation and growth due to SCC is an applicable aging effect for carbon steel bolting, an aging management program will be proposed to manage this effect. This is Confirmatory Item 3.1.2.1-1, Part 1.

The applicant provided the following response to Confirmatory Item 3.1.2.1-1, Part 1, in a letter dated September 16, 2003:

> The RNP Aging Management Review (AMR) has not identified plant-specific or generic industry experience which supports a conclusion that crack initiation and growth due to Stress Corrosion Cracking (SCC) is an applicable aging effect for carbon steel or low-alloy steel bolting materials in the reactor coolant system (RCS). This is supported by operating experience and existing data which indicate that SCC failure should not be a significant issue for closure bolting within the RCS.

The applicant's response to Confirmatory Item 3.1.2.1-1, Part 1, confirms that there has not yet been any RNP-specific or generic operating experience to support the conclusion that SCC-induced cracking is an aging issue for carbon steel bolting materials in ASME Class 1 systems. The staff therefore concludes that SCC-induced cracking is not an aging effect requiring aging management for ASME Class 1 carbon steel bolting made from carbon steel materials. The staff therefore considers Confirmatory Item 3.1.2.1-1, Part 1, to be resolved and Confirmatory Item 3.1.2.1-1, Part 1, is closed.

Aging of RCS bolting materials other than the RV closure head studs and the SG primary and secondary manway and handhole bolts —Management of crack initiation and growth due to thermal fatigue (cumulative fatigue damage)

The staff's AMR evaluations for GALL commodity group items IV.C2.3-d and IV.C2.4-d identify that cumulative fatigue damage is an applicable effect for RCP bolts (GALL component IV.C2.3.3) and RCS valve bolting (GALL component IV.C2.4.3). The applicant's evaluation discussion for AMR 22 of LRA Table 3.1-1 did not address whether cumulative damage from thermal fatigue is an applicable aging effect for the RCS bolting other than the bolting (studs) used to secure the RV head closure assembly and the SG primary and secondary manways and handholes. In RAI 3.1-2.1-3, the staff requested, in part, that the applicant provide a technical basis for concluding that thermal fatigue is not considered to be an applicable aging effect for all RCS bolting other than that used to secure the RV head closure assembly and the SG primary and secondary manways and handholes. In its response to RAI 3.1.2.1-3, the applicant stated, in part, that the discussion for AMR Item 22 of LRA Table 3.1-1 was not meant to imply that cumulative damage from thermal fatigue is not an applicable aging effect for the RCS bolting. The applicant clarified that cumulative damage due to thermal fatigue is identified as an aging effect for RCPB bolting, and evaluated in one of the time-limited aging analyses (TLAAs) for the application (refer to Section 4.3 of the SER).

The applicant's response clarifies that cumulative fatigue damage of the RCS bolting (other than that used to secure the RV head closure assembly and the SG primary and secondary manways and handholes) has been adequately evaluated and addressed by the applicant, as given in AMR 1 of LRA Table 3.1-1 and in the applicant's TLAA for thermal fatigue, as given in Section 4.3 of the application. Based on this review, the staff concludes that the applicant's basis for managing cumulative damage due to thermal fatigue in the RCS bolting (other than that used to secure the RV head closure assembly and the SG primary and secondary manways and handholes) is acceptable, and this portion of RAI 3.1.2.1-3 is resolved. The staff evaluates AMR 1 of LRA Table 3.1-1 and cumulative damage due to thermal fatigue in Section 3.1.2.2.1 of this SER. The staff evaluates the applicant's TLAA for thermal fatigue of Class 1 and Class 2 components in Section 4.3 of this SER.

Aging of RCS bolting materials other than the RV closure head studs and the SG primary and secondary manway and handhole bolts—Management of loss of preload due to stress relaxation

The staff's AMR evaluations for GALL commodity group items IV.A2.2-f, IV.C2.3-g, and IV.C2.4-g identify the loss of preload due to stress relaxation as an applicable effect for CRDM flange bolts (GALL component IV.A2.2.3), RCP bolts (GALL component IV.C2.3.3), and RCS valve bolting (GALL component IV.C2.4.3). In AMR Item 22 of LRA Table 3.1-1, the applicant concludes that, with the exception of the bolts used to secure the primary and secondary manways in the SGs, loss of preload due to stress relaxation is an applicable aging effect for all RCS Class 1 bolting components and RCS Class 2 bolting components greater than 2 inches in diameter. In its response to RAI 3.1.2.1-3, the applicant provided additional information regarding its AMP for managing stress relaxation in these components:

> Loss of preload of mechanical flanged joints, valve body-to-bonnet joints, and pressure retaining bolting associated with pumps or other process components can occur due to settling of mating surfaces, relaxation after cyclic loading, gasket creep, and loss of gasket compression due to differential thermal expansion. RNP has developed a bolting and torque program based on EPRI guidance that considers material properties, joint and gasket design, and service requirements in specifying torque and closure requirements.

The assessment in AMR Item 22 of LRA Table 3.1-1 evaluating loss of preload due to stress relaxation applies to more RCS bolting components than are identified in Section IV of GALL, Volume 2, and is therefore more conservative than GALL and is acceptable. The applicant credits the Bolting Integrity Program for managing wear in these components. This is consistent with the AMP credited in the AMR analysis for GALL commodity group IV.A2.2-f and is also acceptable. However, in its response to RAI 3.1.2.1-3, the applicant concluded that "loss of preload due to stress relaxation is not an aging effect requiring management for RCPB valve closure bolting, manway and holding bolting, or other closure bolting in high pressure and high temperature systems."

The staff has the following issue with the applicant's response to RAI 3.1.2.1-1 as it pertains to managing loss of preload due to stress relaxation in the Class 1 RCS valve bolting (i.e., RCPB valve closure bolting) and other closure bolting in high pressure and high temperature systems. The applicant's response to RAI 3.1.2.1-3 states that "stress relaxation is not applicable to valve closure bolting in the RCP boundary (i.e., RCPB valve bolting) and other closure bolting in high pressure and high temperature systems." However, the applicant's discussion for AMR 22 of LRA Table 3.1-1 states that the Bolting Integrity Program is applicable to all RCPB bolting except RV studs for which the Reactor Head Closure Studs Program applies, and that the

Bolting Integrity Program relies on the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program to assure that aging effects associated with wear and stress relaxation are managed for RCS Class 1 closure bolting and for Class 2 bolting greater than 2 inches in diameter. The applicant's discussion for AMR 22 of LRA Table 3.1-1 did not indicate that the applicant was exempting stress relaxation as an applicable aging effect for the RCPB valve bolting or other closure bolting in high pressure and high temperature systems." Therefore, the staff concludes that the applicant's response to RAI 3.1.2.1-3, as it pertains to the management of stress relaxation in the RCPB valve bolting or other closure bolting in high pressure and high temperature systems," contradicts the applicant's discussion for AMR 22 of LRA Table 3.1-1. The staff requests confirmation that, other than SCC, the aging effects identified in AMR 22 of LRA Table 3.1-1 are still applicable to the RCS bolting within the scope of the commodity group, other than the SG primary and secondary manway and handhole bolting. The applicant should explain the contradiction in the RAI response and the information in AMR 22 of LRA Table 3.1-1. This is Confirmatory Item 3.1.2.1-1, Part 2.

The applicant provided the following response to Confirmatory Item 3.1.2.1-1, Part 2, in a letter dated September 16, 2003:

> RAI 3.1.2.1-3 requested a technical basis for concluding why loss of preload due to stress relaxation is not applicable to steam generator manways. Accordingly, the response to RAI 3.1.2.1-3 relative to "loss of preoad due to stress relaxation" should have been applied to the steam generator manways only. RNP confirms that, other than SCC, the aging effects identified in AMR 22 to LRA Table 3.1-1 are still applicable to the RCS bolting within the scope of the commodity group.

The applicant's response to Confirmatory Item 3.1.2.1-1, Part 2, confirms that, other than SCC, loss of materials due to wear and loss of preload due to stress relaxation are applicable aging effects requiring aging management for the RCS bolting materials within the scope of AMR 22 in LRA Table 3.1-1. The staff therefore considers Confirmatory Item 3.1.2.1-1, Part 2, to be resolved and Confirmatory Item 3.1.2.1-1, Part 2 is closed.

The applicant also credits the preventive maintenance (PM) activities for managing loss of preload due to stress relaxation in the RCP bolts. This is a supplemental AMP to those credited for managing stress relaxation in commodity group item IV.C2.3-g and is acceptable.

Management of aging effects for the SG primary and secondary manway and handhole bolts other than SCC

The applicant stated that loss of material due to aggressive chemical attack (i.e., boric acid corrosion from leaks of the primary coolant) and crack initiation and growth due to thermal fatigue are the only applicable aging effects for the SG primary and secondary manway bolts and that the alternate AMR in AMR Item 12 of LRA Table 3.1-2 assesses aging in these components in further detail. The applicant credits the Boric Acid Corrosion Program with managing loss of material due to chemical attack in SG primary and secondary manway bolts. The applicant credits its TLAA for thermal fatigue, as given in Section 4.3 of the LRA, with managing cracking of the SG primary and secondary manway bolts as a result of thermal fatigue. The staff evaluates AMR 12 of LRA Table 3.1-2 and management of stress relaxation and thermal fatigue in the SG primary and secondary manway and handhole bolts in Section 3.1.2.4.6.8 of this SER. The staff evaluates the applicant's TLAA for thermal fatigue of

ASME Class 1 and Class 2 materials in Section 4.3 of this SER. The staff evaluates the Boric Acid Corrosion Program in Section 3.0.3.4 of this SER.

The staff's AMR evaluations for GALL commodity group item IV.D1.1-f identify that stress relaxation is an applicable aging for SG secondary manway and handhole bolting (GALL component D1.1.7). The applicant's discussion in AMR 22 implies that loss of material due to wear and loss of preload due to stress relaxation are not applicable aging effects for the bolts used to secure the primary and secondary SG manways. In RAI 3.1.2.1-3, the staff requested a technical basis for the applicant's conclusion that loss of material due to wear and loss of preload due to stress relaxation are not applicable aging effects for the bolts used to secure the primary and secondary SG manways and handholes. There are no SG primary handholes, only manways.

In its response to RAI 3.1.2.1-3, dated April 28, 2003, the applicant stated that in LRA Table 3.1-1, Item 22, the applicable aging effects for the SG primary and secondary closure bolts are "cracking from thermal fatigue" and "loss of mechanical closure integrity from loss of material due to aggressive chemical attack." The applicant stated that loss of material due to wear is not identified by GALL as an aging effect requiring management for the SG primary and secondary SG manway closure bolting (refer to GALL commodity groups IV.D1.1-f and IV.D1.1-l). Consistent with GALL, the staff agrees that wear is not considered applicable to RNP SG manway bolting.

However, as stated previously, the AMR analysis for GALL commodity group IV.D1.1-f does identify that loss of preload due to stress relaxation is an applicable aging effect for SG secondary manway and handhole bolting. In its response to RAI 3.1.2.1-3, the applicant stated that it recognizes that loss of preload due to stress relaxation can occur in these secondary side SG components. However, contrary to this determination, the applicant concluded that loss of preload due to stress relaxation is not an aging effect requiring management for RCPB valve closure bolting, SG manway and holding bolting, or other closure bolting in high pressure and high temperature systems.

The staff has an issue with the applicant's response to RAI 3.1.2.1-3 as it pertains to whether or not stress relaxation needs to be managed in the SG primary and secondary manway and handhole bolts. In its response to RAI 3.1.2.1-3, the applicant states that it recognizes that stress relaxation can occur in the SG manway and handhole bolting, at least for the bolting on the secondary side of the SGs, and states that a Bolting and Torque Program has been developed to enable the applicant to determine the closure and torque requirements for RCS closure bolting. GALL IV. D.1.1.7 identifies that loss of preload due to stress relaxation is an aging effect for the SG secondary manway and handhole bolting and GALL XI.M18, "Bolting Integrity," is the AMP to manage this aging effect. As required by 10 CFR 54.21(1), license renewal applicants must perform AMRs and identify all applicable aging effects for passive components within the scope of license renewal. The SG primary and secondary manway and handhole bolts are passive components within the scope of license renewal. The applicant has stated that stress relaxation is an applicable aging effect for the SG secondary manway and handhole bolting; therefore, the applicant is required by 10 CFR 54.21(a)(3) to propose an AMP to manage the aging effect. The staff also requests the applicant to provide technical justification as to why loss of preload stress relaxation does not have to be managed for the primary SG manway bolts in the same manner as for the SG secondary side bolting. In subsequent discussions with the NRC staff to resolve this issue, the applicant stated that the RNP Bolting Integrity Program in LRA Section B.3.4 will be applied to the pressure retaining bolting for the primary and secondary side of the steam generators because the RNP Bolting Integrity Program can be relied upon to prevent the loss of preload and that the RNP Bolting Integrity Program will not take exception to the scope of program in GALL XI.M18, "Bolting Integrity." The staff evaluates the RNP Bolting Integrity Program in Section 3.0.3 of this SER. The staff finds the applicant's resolution of the issue acceptable because the applicant credits its Bolting Integrity Program to manage loss of preload due to stress relaxation in the SG primary and secondary manway and handhole bolts. However, the applicant needs to submit its resolution under oath and affirmation; therefore, this is Confirmatory Item 3.1.2.1-1, Part 3.

Conclusions for the staff's evaluation of AMR 22 of LRA Table 3.1-1

The staff has reviewed AMR Item 22 of LRA Table 3.1-1, as amended by the information in the applicant's response to RAI 3.1.2.1-3, and as the information pertains to aging management of loss of preload due to stress relaxation, crack initiation and growth due to thermal fatigue and/or SCC, and loss of material due to wear in RCS bolting at RNP. The staff cannot at this time conclude that AMR Item 22 of LRA Table 3.1-1 and the applicant's response to RAI 3.1.2.1-3 are acceptable because the applicant needs to provide (1) additional confirmatory information to support the conclusion that SCC does not need to be managed for carbon steel or low alloy steel bolting in the RCS and (2) additional confirmatory information to support the conclusion that loss of preload due to stress relaxation needs to be managed by an AMP for the bolting components within the scope of this AMR. Pursuant to 10 CFR 54.21(a)(3), the staff requires acceptable resolution of Confirmatory Item 3.1.2.1-1, Parts 1, 2, and 3 to conclude that AMR Item 22 of LRA Table 3.1-1 is acceptable.

<u>Item 23—Crack initiation and growth due to PWSCC in RCS CRDM nozzles—corresponding GALL-2 entries are IV.A2.2-a and IV.A2.7-b</u>

AMR Item 23 of LRA Table 3.1-1 (page 3.1-22 of the LRA) evaluates the potential for crack initiation and growth by PWSCC to affect the structural integrity of RV head penetration nozzles made from Alloy 600. In this AMR, the applicant identifies that crack initiation and growth by PWSCC is applicable to the CRDM nozzles fabricated from Alloy 600 and proposes to use the Nickel-Alloy Nozzles and Penetrations Program and the Water Chemistry Program to manage this effect. The staff determined that AMR Item 23 of LRA Table 3.1-1 was consistent with the corresponding AMR for CRDM nozzles in Item IV.A2.2-a of GALL-2. However, in RAI 3.1.2.1-4, the staff requested clarification as to whether components within the scope of AMR Item 23 include the RV head vent nozzle or RV head instrumentation nozzles at RNP.

In its response to RAI 3.1.2.1-4, dated April 28, 2003, the applicant stated that it did not take any exceptions to GALL, Volume 2, commodity group items IV.A2.2-a (which bounds commodity group component IV.A2.2.1, CRDM nozzle) and IV.A.2.2-b (which bounds commodity group component IV.A2.2.2, CRDM housing). The applicant's response to RAI 3.1.2.1-4 is acceptable because it clarifies that the RV head vent pipe and instrumentation tubes are within the scope of the commodity group evaluated in AMR 23 of LRA Table 3.1-1. Based on this review, the staff concludes that AMR 23 of LRA Table 3.1-1 is consistent with the corresponding AMR in commodity group item IV.A2.2-a and IV.A2.2-b of GALL, Volume 2, and is acceptable. RAI 3.1.2.1-4 is resolved.

The staff evaluates the ability of the Alloy 600 Inspection Program to detect and manage PWSCC in the RNP VHP nozzles fabricated from Alloy 600 and to address the impacts of the Davis Besse VHP nozzle cracking on the Alloy 600 Inspection Program in Section 3.1.2.3.2.2.

<u>Item 24—Crack initiation and growth (SCC, PWSCC, and/or cyclic loading) in RCS nozzle safe-ends, CRDM housings, and RCS components other than bolting materials or RCS components made from CASS—corresponding GALL-2 entries are IV.A2.2-b, IV.A2.4-b, IV.C2.1-c, IV.C2.2-f, IV.C2.5-c, IV.C2.5-g, IV.C2.5-h, IV.C2.5-m, IV.C2.5-r, and IV.C2.6-c</u>

AMR Item 24 of LRA Table 3.1-1 (page 3.1-22 of the LRA) evaluates whether crack initiation and growth due to cyclic loading, SCC, and/or PWSCC are applicable to the RCS nozzle safe-ends, CRDM housings, and RCS components other than bolting materials or RCS components made from CASS. In this AMR, the applicant concludes that crack initiation and growth due to cyclic loading, SCC, and/or PWSCC are aging effects that need to be managed in these components during the extended period of operation and credits the ASME Code Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program with managing these aging effects. The AMRs in commodity group items IV.A2.2-b, IV.A2.4-b, IV.C2.1-c, IV.C2.2-f, IV.C2.5-c, IV.C2.5-g, IV.C2.5-h, IV.C2.5-m, IV.C2.5-r, and IV.C2.6-c of GALL, Volume 2, provide the staff's corresponding AMR for managing crack initiation and growth due to cyclic loading, SCC, and/or PWSCC in the RCS nozzle safe-ends, CRDM housings, and RCS components other than bolting materials or RCS components made from CASS.

In RAI 3.1.2.1-5, the staff asked the applicant to discuss how the AMR analysis in Item 24 of LRA Table 3.1-1 addressed the potential implications and lessons learned from the V.C. Summer hot-leg nozzle cracking, and specifically how the applicant's AMR analysis resolved potential issues identified in IN 2000-17; 2000-17, Supplement 1; and 2000-17, Supplement 2, (dated October 18, 2000, November 16, 2000, and February 28, 2001, respectively), as they related to the Summer cracking event.

The applicant's response to RAI 3.1.2.1-5 clarifies that the V.C. Summer issue was considered in the Alloy 600 Strategic Plan. As a result of the V.C. Summer issue, the 10-year ISI volumetric examinations performed during RFO-20 for the RCS hot-leg safe-end nozzle welds were enhanced to incorporate lessons learned from the V.C Summer cracking event. No reportable indications were found as a result of these inspections. The applicant's response indicates that the followup inspections for the RC hot-leg safe-end nozzle welds will be performed as a part of the ongoing Alloy 600 management strategy.

The applicant's response to RAI 3.1.2.1-5 implies that the followup inspections of the RNP hot-leg safe-end nozzle welds will incorporate any pertinent recommendations from industry-wide working groups on Alloy 600 degradation which are acceptable to the NRC. The staff's review of the applicant's response to RAI B.4.1-1 indicates that the applicant has committed to continued participation in the Westinghouse Owner's Group (WOG) and EPRI Material Reliability Project (MRP) activities on nickel-based alloys (refer to Item 31 of Attachment II to Serial RNP-RA/03-0031). The applicant's commitment includes a commitment to implement any augmented activities that may be recommended by the WOG or the EPRI-MRP to address PWSCC of Inconel components and welds, as approved by the NRC, or any further requirements that may be imposed by the staff to resolve the issue of PWSCC in Class

1 Inconel base metal or weld components.[2] This commitment also includes a commitment to submit, for review and approval, CP&L's inspection plan for the Nickel-Alloy Nozzles and Penetrations Program, as it will be implemented from the applicant's participation in industry initiatives, prior to July 31, 2009. This commitment will permit ample time for the staff to resolve any implementation or technical issues on the AMP, as it relates to the management of crack initiation and growth in the Alloy 82/182 hot-leg safe-end nozzle welds. The applicant's commitments for the Nickel-Alloy Nozzles and Penetrations Program will also ensure that the implementation of the AMP will be capable of managing PWSCC in Class 1 nickel-based alloy components during the extended period of operation for RNP. Based on this analysis and the commitments provided by the applicant, the staff concludes that AMR Item 24 of LRA Table 3.1-1 is consistent with the staff's corresponding AMR in commodity group item IV.C2.2-f of GALL, Volume 2. The staff therefore concludes that AMR Item 24 of LRA Table 3.1-1 is acceptable and no further assessment of this AMR is necessary.

Item 25—Loss of fracture toughness (thermal aging or neutron irradiation embrittlement) in reactor vessel internal CASS components—applicable GALL-2 entries for Westinghouse internals are IV.B2.1-g and IV.B2.5-m

AMR 25 of LRA Table 3.1-1 evaluates whether or not loss of fracture toughness due to thermal aging or neutron irradiation embrittlement and void swelling are applicable aging effects for RV internal components made from CASS. In the discussion section of AMR 25 of LRA Table 3.1-1, the applicant states that the AMR analysis for this commodity group is not consistent with GALL. The applicant states that loss of fracture toughness in CASS RV internal components is addressed in AMR Item 14 of LRA Table 3.1-2. The applicant credits the PWR Vessel Internals Program with managing these aging effects. The staff evaluates Item 8 of Table 3.1-1 in Section 3.1.2.2.6 of this SER. The staff evaluates AMR Item 14 of LRA Table 3.1-2 in Section 3.1.2.4.5.3 of this SER. The staff evaluates the ability of the PWR Vessel Internals Program to manage void swelling and loss of fracture toughness in CASS in Section 3.1.2.3.4.2 of this SER. The staff concludes that AMR 25 of LRA Table 3.1-1 is acceptable because it clarifies which AMR items in the application actually provide the applicant's AMRs for managing void swelling and loss of fracture toughness for the RV internals made from CASS.

Item 26—External surfaces of carbon steel components in the reactor coolant pressure boundary —applicable items in GALL-2 for Westinghouse plants are IV.A2.1-a, IV.A2.5-e, IV.A2.8-b, IV.C2.1-d, IV.C2.2-d, IV.C2.3-f, IV.C2.4-f, IV.C2.5-b, IV.C2.5-o, IV.C2.5-u, IV.C2.6-b, IV.D1.1-g, and IV.D1.1-k

AMR Item 26 of LRA Table 3.1-1 evaluates whether or not loss of material due to aggressive chemical attack is an applicable aging effect for the external surfaces of carbon steel or low-alloy steel components in the RCPB. In this AMR, the applicant identified that corrosion due to potential exposure to concentrated boric acid is an applicable aging effect for the external surfaces of all carbon steel components in the RCPB, and that the Boric Acid Wastage Program will be used to manage this aging effect in the RCPB components.

[2]This would include requirements that are imposed the process of rulemaking (10 CFR Part 2, Subpart H) or the issuance of orders (10 CFR Part 2, Subpart B, Paragraph §2.202). For the imposition of additional requirements needed for resolution of 10 CFR Part 50 issues, these processes would have to be in conformance with the backfit provisions of 10 CFR 50.109.

In RAI 3.1.2.1-6, Part 1, the staff informed the applicant that the AMR for commodity group V.E.1-b of GALL, Volume 2, identifies that loss of material due to general corrosion is an applicable aging effect for the external surfaces of carbon steel and low-alloy steel PWR components that are exposed to moist, humid, or damp atmospheric environments. In this RAI, the staff asked the applicant to provide its AMR for the external surfaces of the carbon steel or low-alloy steel RCPB components that are exposed to atmospheric environments. With respect to this AMR, the staff asked the applicant to identify all aging effects that are applicable to these components under exposure to the atmospheric environments and, if aging effects were determined applicable for these conditions, to propose applicable aging management activities or programs to manage the aging effects during the period of extended operation for RNP.

In its response to RAI 3.1.2.1-6, Part 1, the applicant stated that any carbon steel and low-alloy steel RCPB components which are indoors are not exposed to weather and are therefore not considered to be susceptible to loss of material induced by general corrosion. The applicant's general response to RAI 3.2.1-1 provides the technical bases for determining whether loss of material due to general corrosion is an applicable aging effect for carbon steel or low-alloy steel components that are exposed to wet, moist, or humid environments. The applicant stated that general corrosion of carbon steel or low-alloy steel components would only be applicable if the components were exposed to outdoor environments or to indoor environments that could promote the condensation of water on the external surfaces of the components. The applicant stated that condensation of water is therefore not likely to occur on these components, and loss of material due to general corrosion is not an applicable aging effect for the external surfaces of Class 1 carbon steel or low-alloy steel components that are exposed to indoor environments. This implies that the Class 1 carbon steel or low-alloy steel components have temperatures that are equivalent to or hotter than the ambient temperature for the surrounding containment air or indoor air environments. This appears to be consistent with Section IV of GALL, Volume 2, which does not identify that general corrosion is applicable to Class 1 carbon steel/low-alloy steel components.

The staff concurs that general corrosion of carbon steel or low-alloy steel components in moist or humid indoor environments is only applicable if condensation could occur on the external surfaces of the components. However, in order to provide reasonable assurance that general corrosion is not an applicable aging effect for the Class 1 carbon steel or low-alloy steel components in containment air or indoor air environments, the staff seeks confirmation that the Class 1 carbon steel or low-alloy steel components operate at temperatures that are equivalent to or hotter than the ambient temperature for the surrounding containment air or indoor air environments. This is Confirmatory Item 3.1.2.1-2.

The applicant provided the following response to Confirmatory Item 3.1.2.1-2 in a letter dated September 16, 2003:

> RNP confirms that Class 1 carbon steel or low-alloy steel components operate at temperatures that are equivalent to or hotter than the ambient temperature for the surrounding containment air or indoor air environments.

The applicant's response to Confirmatory Item 3.1.2.1-2 confirms that the Class 1 carbon steel or low-alloy steel components in the RCS operate at temperatures equivalent to or hotter than the ambient temperatures for their external atmospheric environments (i.e., the containment air or indoor air environments). Based on the applicant's response, the staff concludes that precipitation on the components will not be a concern for the extended period of operation for RNP and that general corrosion induced by precipitation on the Class 1 carbon steel or low-alloy steel components is not an aging effect requiring aging management during the extended period of operation for RNP. Confirmatory item 3.1.2.1-2 is therefore resolved and Confirmatory Item 3.1.2.1-2 is closed.

In RAI 3.1.2.1-6, Part 2, the staff informed the applicant that components within the scope of AMR Item 26 did not appear to include ASME Class 1 RCS components from low-alloy steel (including RV shells and heads made from low-alloy steel grades). The staff considers low-alloy steel components to be susceptible to boric acid corrosion in a manner similar to carbon steel components. The discussion column of Item 26 in LRA Table 3.1-1 also did not address the implications of the Davis Besse boric acid wastage event on the ability of the Boric Acid Corrosion Program to manage potential boric acid corrosion-induced wastage of carbon steel and low-alloy steel components of the RCS. Therefore, in the RAI, the staff asked the applicant to amend Item 26 in LRA Table 3.1-1 to (1) include both carbon steel and low-alloy steel ASME Class 1 components among the Class 1 RCS components that could potentially be affected by loss of material as a result of boric acid corrosion-induced wastage, and (2) include how the implications and lessons learned from the Davis Besse boric acid wastage event have been addressed/resolved relative to the AMR for Item 26. The staff also asked the applicant to indicate whether the RCS inlet, outlet, and SI nozzles, as well as the primary SG manway covers and bolts, are susceptible to this aging effect and whether the scope of the AMR in Item 26 to LRA Table 3.1-1 includes these components.

In its response to RAI 3.1.2.1-6, Part 2, the applicant stated that the RNP method used to evaluate aging effects of carbon steel in the air/gas external environment does not distinguish between low-alloy steel and carbon steel in determining susceptibility to boric acid wastage. For both carbon and low-alloy steel, the only criterion considered in this regard is whether a given SSC is potentially exposed to a boric acid environment (i.e., one that contains borated water or is in the proximity of borated water systems). The applicant clarified that the vessel head, flange, shell, and inlet/outlet nozzles, as well as the SG primary manway covers and bolting, are considered susceptible to boric acid wastage and are therefore within the scope of AMR 26 to LRA Table 3.1-1.

The staff finds that the applicant's response to RAI 3.1.2.1-6, Part 2, is acceptable because the applicant has clarified that the vessel head, flange, shell, and inlet/outlet nozzles, as well as the SG primary manway covers and bolting, are considered susceptible to boric acid wastage. The applicant also stated that the implication of the Davis Besse lessons learned are addressed in the applicant's responses to NRC Bulletins 2002-01 and 2002-02. The applicant stated that it will use the Boric Acid Corrosion Program to manage aggressive chemical attack (boric acid-induced corrosion) of the components that are within the scope of AMR Item 26 of LRA Table 3.1-1. The staff evaluates this AMP in Section 3.0.3.4 of this SER, which includes further discussion of NRC Bulletin 2002-01 as it pertains to this AMP. Based on this information, the staff concludes that AMR 26, as it relates to boric acid-induced corrosion of the carbon and low-alloy steel components in the RCPB (including SG manway covers and bolting) is consistent with the corresponding AMR given in commodity group items IV.A2.1-a, IV.A2.5-e, IV.A2.8-b, IV.C2.1-d, IV.C2.2-d, IV.C2.3-f, IV.C2.4-f, IV.C2.5-b, IV.C2.5-o, IV.C2.5-u, IV.C2.6-b, IV.D1.1-g, and IV.D1.1-k of GALL, Volume 2. Based on this analysis, the staff concludes that

AMR 26 of LRA Table 3.1-1 is acceptable and RAI 3.1.2.1-6 is resolved.

Item 27—Loss of material due to erosion in steam generator secondary manways and handholes (carbon steel)—applicable item in GALL-2 for Westinghouse plants is IV.D1.1-f

AMR Item 27 of LRA Table 3.1-1 (page 3.1-24 of the LRA) evaluates whether or not loss of material by erosion is an applicable aging effect for the SG secondary manways and handholes. The applicant stated that the GALL Report indicates that this item is applicable to once-through SG; therefore, it is not applicable to RNP. For the SG secondary manways and handholes in recirculating SGs (GALL component IV.D.1.1.7), the staff's corresponding AMR is specified in AMR commodity group item D1.1-f (page IV D1-4) of GALL, Volume 2. RNP has recirculating SG.

In RAI 3.1.2.1-7, the staff requested the applicant to provide its AMRs, including identification of aging effects and AMPs, if applicable, of the secondary manways and handholes. If erosion of the RNP SG secondary manways and handholes is not determined to be an applicable effect for the RNP SG secondary manways and handholes, the staff requested the applicant to provide the technical basis for deviating from the staff's AMR given in AMR commodity group item D1.1-f (page IV D1-4) of GALL, Volume 2.

In its response to RAI 3.1.2.1-7, the applicant stated that, for the SG secondary manway and handhole bolting, the applicable AMRs are AMR Item 1 of LRA Table 3.1-1 and AMR Item 12 of LRA Table 3.1-2. The corresponding AMR in GALL is given in commodity group item IV.D1.1-f of GALL, Volume 2. AMR Item 1 of LRA Table 3.1-1 evaluates crack initiation and growth of Class 1 components that results from thermal fatigue. Thermal fatigue of Class 1 components is evaluated in Section 4.3 of the LRA as a TLAA that falls within the scope of the definitions for TLAAs in 10 CFR 54.3. The staff evaluates AMR 1 of Table 3.1-1 in Section 3.1.2.2.1 of this SER and the applicant's TLAA for thermal fatigue in Section 4.3 of this SER. Item 12 of LRA Table 3.1-2 evaluates loss of mechanical closure integrity of bolted Class 1 connections as a result of aggressive chemical attack of the bolted components. The applicant credits the Boric Acid Corrosion Program with managing this aging effect. The staff evaluates the Boric Acid Corrosion Program in Section 3.0.3 of this SER.

For the SG secondary manway and handhole covers (non-GALL components), the applicable AMRs are Item 1 of LRA Table 3.1-1 and Item 5 of LRA Table 3.1-2 which evaluate loss of material due to crevice corrosion, general corrosion, and pitting corrosion in SG components. The applicant credits the Water Chemistry Program with managing this aging effect.

The design of the secondary manways and handholes precludes the potential for wall thinning due to erosion. The secondary manways and handholes are located in areas of large cross section where velocity is low and erosion is not an aging concern. RNP plant-specific operating experience confirms that these components are not susceptible to this aging effect. The staff concurs that the large cross-sectional areas for the SG manways and handholes will not result in high flow velocities across these components and, therefore, loss of material by erosion will not be an applicable aging effect for these components. The staff finds that the applicant's response to RAI 3.1.2.1-3 is acceptable because the applicant provided an acceptable technical basis for concluding that loss of material by erosion is not an aging effect that needs to be managed in the secondary manways and handholes during the extended period of operation for RNP.

Based on this assessment, the staff concludes that the AMR given in commodity group Item IV.D1.1-f of GALL, Volume 2, is not applicable to the scope of the applicant's LRA.

Item 28—Loss of material due to wear in reactor internals, reactor vessel closure studs, and core support pads—applicable GALL-2 items for Westinghouse designs are IV.A2.1-d, IV.A2.5-f, IV.B2.1-l, IV.B2.5-o, and IV.B2.6-c

The scope of AMR Item 28 of LRA Table 3.1-1 (page 3.1-25 of the LRA) evaluates whether or not loss of material due to wear is an applicable effect for the RV internals, RV closure studs, and RV core support pads. With the exception of the RV closure studs and neutron flux thimble tubes, the applicant credits the ASME Section XI, Inservice Inspection, Subsection IWB, IWC, and IWD Program to manage wear in these components. The applicant credits the Flux Thimble Eddy Current Inspection Program with managing wear in the neutron flux thimble tubes. The applicant credits the Reactor Head Closure Studs Program with managing wear in the RV closure studs. In its review of AMR Item 28 of LRA 3.1-1, the staff determined that the description in the discussion section of the AMR was consistent with guidance provided in the staff's corresponding AMRs in commodity group items IV.A2.1-d, IV.A2.5-f, IV.B2.1-l, IV.B2.5-o, and IV.B2.6-c of GALL, Volume 2. The staff evaluates the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program in Section 3.0.3 of this SER. The staff evaluates the Flux Thimble Eddy Current Inspection Program in Section 3.1.2.3.7 of this SER. The staff evaluates the Reactor Head Closure Studs Program in Section 3.1.2.3.1 of this SER. Based on this analysis, the staff concludes that AMR Item 28 of LRA Table 3.1-1 is acceptable and that no further evaluation is necessary.

Item 29—Crack initiation and growth due to cyclic loading in pressurizer integral supports—applicable GALL-2 item for Westinghouse designs is IV.C2.5-v

AMR Item 29 of LRA Table 3.1-1 (page 3.1-26 of the LRA) evaluates whether or not crack initiation and growth due to cyclic loading is an applicable aging effect for the pressurizer integral supports. In this AMR, the applicant identifies that both crack initiation and growth due to cyclic loading and loss of material due to aggressive chemical attack are applicable aging effects for the carbon steel pressurizer integral supports. In its review of AMR Item 28 of LRA 3.1-1, the staff determined that the description in the discussion section of the AMR was consistent with the staff's corresponding AMR for commodity group item IV.C2.5-v of GALL, Volume 2. AMR Item 29 is also slightly more conservative than the AMR for commodity group item IV.C2.5-v because commodity group item IV.C.2-v does not identify that loss of material due to aggressive chemical attack (i.e., postulated exposure to leaks of the borated reactor coolant) is an applicable aging effect for the pressurizer integral supports. Since the applicant's AMR in Item 28 of LRA Table 3.1-1 is consistent with and slightly more conservative than the corresponding AMR analysis in GALL, Volume 2, the staff concludes that AMR Item 28 of LRA Table 3.1-1 is acceptable and that no further evaluation is necessary.

Item 30—Loss of preload due to stress relaxation in Westinghouse design reactor vessel internal upper and lower assemblies—applicable GALL-2 items for Westinghouse designs are IV.B2.1-d, IV.B2.5-h, and IV.B2.5-i

In AMR Item 30 of LRA Table 3.1-1 (page 3.1-26 of the application), the applicant assesses whether or not fastened or bolted components in the RV internal upper and lower assemblies are susceptible to loss of preload resulting from stress relaxation (loss of preload/stress relaxation). The corresponding AMRs in GALL, Volume 2, are given in GALL commodity group items IV.B2.1-d, IV.B2.5-h, and IV.B2.5-i and include the upper internals assembly hold down springs, lower support plate column bolts, and clevis insert bolts in the lower internals assembly. GALL recommends that the following AMPs be used to manage loss of preload/stress relaxation in these components:

- the ISI plan for ASME IWB, IWC, and IWD components and loose parts monitoring activities (GALL XI.M14) for the upper support column bolts (commodity group IV.B2.1-k, GALL component IV.B2.1.3) and lower support column bolts (commodity group IV.B2.5-h, GALL component IV.B2.5.5)

- the ISI plan for ASME IWB, IWC, and IWD components and either the loose parts monitoring activities or neutron noise monitoring activities (GALL Program XI.M15) for the upper internals assembly hold-down springs (commodity group IV.B2.1-d, GALL component B2.1.7) and clevis insert bolts in the lower internal assembly (commodity group IV.B2.5-i, GALL component B2.5.7)

In RAI 3.1.2.1-8, the staff informed the applicant that AMR Item 30 of LRA Table 3.1-1 did not list the applicable lower and upper internal assembly subcomponents that are subject to loss of preload resulting from stress relaxation, and that the AMR for the lower internal assembly clevis insert pins was not consistent with GALL because the applicant used a slightly different combination of AMPs to manage loss of preload in the clevis insert pins. In the RAI, the staff asked the applicant to (1) clarify which of the bolted or fastened components in the RV internal upper and lower assemblies are considered to be susceptible to loss of preload/stress relaxation, (2) assess the consistency of the AMRs for these components against the corresponding AMRs for the components given in GALL, Volume 2, and (3) confirm that the actual AMR for these components is given in AMR Item 15 of LRA Table 3.1-2.

In its response to RAI 3.1.2.1-8, dated April 28, 2003, the applicant stated that the components within the scope of AMR Item 30 of LRA Table 3.1-1 encompass the RV internal upper and lower assemblies, including the upper support column bolts, upper internal assembly hold-down spring, lower support plate column bolts, and lower internals assembly clevis insert bolts. The applicant also stated that CP&L does not credit the Loose Parts Monitoring Program (GALL XI.M14) or the Neutron Noise Monitoring Program (GALL XI.M15) with aging management. The applicant clarified that the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program and the PWR Vessel Internals Program will be used to manage loss of preload/stress relaxation in the upper support column bolts, upper internal assembly hold-down spring, lower support plate column bolts, and lower internals assembly clevis insert bolts. The applicant stated that, because this is an inconsistency from the corresponding AMRs in GALL, Volume 2, the corresponding AMR for these components is given in AMR Item 15 of LRA Table 3.1-2.

The applicant's response to RAI 3.1.2.1-8 clarifies that AMR 30 of LRA Table 3.1-1 is only partially applicable and that AMR Item 15 of LRA Table 3.1-2 provides the actual AMR for evaluating loss of preload/stress relaxation that may occur in the RV upper support column bolts, upper internal assembly hold-down spring, lower support plate column bolts, and lower internals assembly clevis insert bolts (i.e., for the bolted or fastened RCS components that are not within the scope of AMR 30 of LRA Table 3.1-1). The response also clarifies which combination of AMPs will be used to manage this aging effect. Because the RAI response provides the clarifications requested by the NRC, the staff concludes that the applicant's response is acceptable and RAI 3.1.2.1-8 is resolved. The staff evaluates AMR Item 15 of LRA Table 3.1-2 in Section 3.1.2.4.5 of this SER. The staff evaluates the ability of the ASME Section XI, Inservice Inspection, Subsection sIWB, IWC, and IWD Program to manage loss of preload/stress relaxation in fastened or bolted RV internal components in Section 3.0.3 of this SER. The staff evaluates the ability of the PWR Vessel Internals Program to manage loss of preload/stress relaxation in fastened or bolted RV internal components in Section 3.1.2.3.4 of this SER.

<u>Item 31—Loss of fracture toughness due to neutron irradiation embrittlement and/or thermal aging and void swelling in RV internals in the fuel zone (other than Westinghouse and B&W baffle/former bolts)—applicable GALL-2 items for Westinghouse designs are IV.B2.3-c, IV.B2.4-e, IV.B2.5-c, IV.B2.5-g, and IV.B2.5-n</u>

In AMR Item 31 of Table 3.1-1, the applicant concludes that loss of fracture toughness due to neutron irradiation embrittlement and/or thermal aging and void swelling are applicable aging effects for RV internal components within the fuel zone (other than Westinghouse and B&W baffle/former bolts). The corresponding AMR item commodity groups in GALL, Volume 2, are AMR Items IV.B2.3-c, IV.B2.4-e, IV.B2.5-c, IV.B2.5-g, and IV.B2.5-n. These include the following GALL components—core barrel (GALL component IV.B2.3.1), core barrel flange (GALL component IV.B2.3.2), core barrel outlet nozzles (GALL component IV.B2.3.3), thermal shield (GALL component IV.B2.3.4), baffle and former plates (GALL component IV.B2.4.1), lower core plate (GALL component IV.B2.5.1), fuel alignment pins (GALL component IV.B2.5.2), lower support plate column bolts (GALL component IV.B2.5.5), clevis insert bolts (GALL component IV.B2.5.7), lower support forging or casting (GALL component IV.B2.5.3), and lower support plate columns (GALL component IV.B2.5.4).

In RAI 3.1.2.1-9, Part 1, the staff asked the applicant to provide the technical basis for omitting the core barrel flange, core barrel outlet nozzles, thermal shield, and lower support plate columns from the scope of AMR 31 in LRA Table 3.1-1. In the RAI, the staff stated that if any of these components should be included within the scope of AMR Item 31 of LRA 3.1-1, a revision of the AMR item would be needed to identify the AMP to be used to manage loss of fracture toughness due to neutron irradiation embrittlement and void swelling in the components.

In its response to RAI 3.1.2.1-9, Part 1, the applicant stated that AMR 31 only applies to RV internal components made of stainless steel (including CASS) and RV internal components that are exposed to chemically treated water up to 340 °C (644 °F) with accumulated neutron fluences above $1x10^{17}$ n/cm^2(1 x 10^{-1} MeV). The applicant clarified that core barrel, baffle and former plates, lower core plate, fuel alignment pins, and lower support forging are the only components that are within the scope of AMR 31 of LRA Table 3.1-1. The applicant stated that the remaining components within the scope of GALL commodity groups IV.B2.3-c (core barrel flange, core barrel outlet nozzles, and thermal shield), IV.B2.5-g (lower support plate column bolts and clevis insert bolts), and IV.B2.5-n (lower support plate columns) were determined by the CP&L AMR review to be located away from the fuel zone region of the reactor and that the aging of components within the scope of AMR Item 31 of LRA Table 3.1-1 will act as lead predictors for the stainless steel RV internal components not within the scope of the AMR item. The applicant clarified that CP&L has committed (refer to Commitment No. 33 of Attachment II to CP&L Serial RNP-RA/03-0031), however, to participate in industry-wide programs designed by the EPRI-MRP for investigating the impacts of aging on PWR vessel internal components and to submit its inspection plan for the RNP RV internal components 2 years prior to entering the period of extended operation for the Unit.

The applicant's reply to RAI 3.1.2.1-9, Part 1, states that the accumulated neutron fluences for the core barrel flange, the core barrel outlet nozzles, the thermal shield, and the lower support plate columns and their bolts are lower than $1x10^{17}$ n/cm^2 because they are away from the active fuel zone for the reactor. In contrast, the RNP thermal shield is an RV internal stainless steel component that is located within the active fuel zone of the reactor. The applicant is predicating its basis for omitting the thermal shield from the scope of AMR Item 31 of LRA Table 3.1-1 on the basis that the inspections for aging effects in other, more highly irradiated stainless steel RV internal components will act as predictive indicators for the aging effects that may be applicable to the RV thermal shield. The staff seeks confirmation that the RV thermal shield is adjacent to the fuel zone region of the RV, receives a neutron fluence greater than $1x10^{17}$ n/cm^2, is within the scope of the commodity group in AMR Item 31 of LRA Table 3.1-1, and will be managed by the PWR Vessel Internals Program. This is Confirmatory Item 3.1.2.1-3, Part 1.

The applicant provided the following response to Confirmatory Item 3.1.2.1-3, Part 1, in a letter dated September 16, 2003:

> The reactor vessel thermal shield is adjacent to the fuel region of the reactor vessel; its projected neutron fluence will exceed 10^{17} n/cm2. The reactor vessel thermal shield is specifically within the scope of Table 3.1-1, AMR Item 1, AMR Item 8. and AMR Item 33. It is not specifically within the scope of Table 3.1-1, AMR Item 31. However, this component is managed by the same Pressurized Water Reactor (PWR) Vessel Internals Program that is referenced by that AMR item.
>
> In Subsection A.3.1.30 of the LRA, PWR Vessel Internals Program, as revised by subsequent responses to RAI B.4.3-2, RNP commits to the following for the PWR Vessel Internals Program:
>
>> *"The Pressurized Water Reactor (PWR) Vessel Internals Program is a new program that will incorporate the following (l) RNP will continue to participate in industry programs to investigate aging effects and determine the appropriate AMP activities to address baffle and former assembly issues, and to address change in dimensions due to void swelling, (2) as Westinghouse Owners Group and Electric Power Research Institute MRP research projects are completed, RNP will evaluate the results and factor them into the PWR Vessel Internals Program as appropriate, and (3) RNP will implement an augmented inspection during the license renewal term. Augmented inspections, based on required program enhancements resulting from industry programs, will become part of the ASME Boiler & Pressure Vessel Code, Section XI program. Corrective actions for augmented inspections*

will be developed using repair and replacement procedures equivalent to those requirements in ASME Boiler & Pressure Vessel Code, Section XI. RNP will submit, for review and approval, its inspection plan for the PWR Vessel Internals Program, as it will be implemented from the applicant's participation in industry initiatives, 24 months prior to the augmented inspection."

The applicant's response to Confirmatory Item 3.1.2.1-3, Part 1, confirms that the thermal shield is located within the fuel zone area of the reactor core and will have a projected neutron fluence above $1x10^{17}$ n/cm^2 during the period of extended operation. Based on this assessment, the applicant's response to RAI 3.1.2.1-9, Part 1, provides an acceptable basis for omitting the core barrel flange, core barrel outlet nozzles, and lower support plate columns and their bolts from the scope of the AMR item because they are located away from the active fuel zone and will not be exposed to neutron irradiation levels that could decrease the fracture toughness properties of the materials or result in void swelling of the components.

The applicant's response to RAI 3.1.2.1-9, Part 1, as amended by the applicant's response to Confirmatory Item 3.1.2.1-3, Part 1, also provides an acceptable basis for omitting the RNP thermal shield from the scope of AMR Item 31 of LRA Table 3.1-1, because the applicant has committed continued participation in the EPRI-MRP's activities for investigating the aging effects that are applicable to the PWR internals of PWR-designed light-water reactors and to use its participation in the activities as the basis for developing its inspection plan for the PWR Vessel Internals Program. This will include industry initiatives to study the aging effects that are applicable to the thermal shields of PWR-designed light-water reactors and to determine whether nondestructive inspections are warranted for the thermal shields and, if warranted, which inspection methods are most appropriate for the examinations. The applicant has also committed to submitting its inspection plan for the PWR Vessel Internals Program to the staff for review and approval 24 months prior to its implementation. These commitments are given in Commitment No. 33 of Attachment II of CP&L Serial Letter No. RNP-RA/03-0031, dated April 28, 2003. This commitment will permit the staff an opportunity to determine and resolve whether additional inspections are warranted for the RNP RV internals, including the thermal shield. The staff therefore considers RAI 3.1.2.1-9, Part 1, and Confirmatory Item 3.1.2.1-3, Part 1, to be resolved, and RAI 3.1.2.1-9, Part 1, and Confirmatory Item 3.1.2.1-3, Part 1, are closed. For those components that are within the scope of AMR Item 31 (i.e., the core barrel, baffle and former plates, lower core plate, fuel alignment pins, and lower support forging), the staff concludes that the assessment in AMR Item 31 of LRA Table 3.1-1 is consistent with AMRs corresponding AMRs given commodity groups IV.B2.3-c, IV.B2.4-e, IV.B2.5-c, IV.B2.5-g, and IV.B2.5-n of GALL, Volume 2, and is acceptable For those components that are within the scope of AMR Item 31 (i.e., the core barrel, baffle and former plates, lower core plate, fuel alignment pins, and lower support forging), the staff concludes to the assessment in AMR Item 31 of LRA Table 3.1-1 is consistent with AMRs corresponding AMRs given commodity groups IV.B2.3-c, IV.B2.4-e, IV.B2.5-c, IV.B2.5-g, and IV.B2.5-n of GALL, Volume 2, and is acceptable.

In RAI 3.1.2.1-9, Part 2, the staff informed the applicant that Item IV.B2.5-n of GALL, Volume 2, covers loss of fracture toughness due to neutron irradiation and void swelling in lower support forging/casting and in the lower support plate columns. The staff further stated that AMR Item 31 of Table 3.1-1 did not clearly identify whether or not the lower support and lower support plate columns are fabricated from statically CASS materials. The staff stated that if either of these components were fabricated from CASS, loss of fracture toughness due to thermal aging is an applicable aging effect for the components and the "Thermal Aging and Neutron Irradiation Embrittlement of CASS Program" should be proposed to manage this effect.

Therefore, in the RAI, the staff asked the applicant to clarify whether or not the RV internal lower support and lower support plate columns were fabricated from CASS materials, and if so, to provide a supplemental AMR for these components that is consistent with AMR in commodity group item IV.B2.5-m of GALL, Volume 2.

In its response to RAI 3.1.2.1-9, Part 2, dated April 28, 2003, the applicant stated that AMRs for CASS RV internal components at RNP are given in the following AMR items for the application:

- AMR Item 8 of LRA Table 3.1-1, which evaluates changes in dimension of RV internal components as a result of void swelling
- AMR Item 33 of LRA Table 3.1-1, which evaluates crack initiation and growth of RV internal components as a result of stress-corrosion cracking or irradiation-assisted stress-corrosion cracking
- AMR Item 14 of LRA Table 3.1-2, which evaluates loss of fracture toughness of RV internal CASS components as a result of either thermal aging or neutron irradiation embrittlement

The applicant credits the RNP PWR Vessel Internals Program with managing the aging effects for RV internal components made from CASS. The staff evaluates the PWR Vessel Internals Program in Section 3.1.2.3.4.2 of this SER. Since the applicant's response to RAI 3.1.2.1-9, Part 2, clarifies which AMRs are applicable to the assessment of aging effects for the RV internal components made from CASS, the staff concludes that RAI 3.1.2.1-9, Part 2, is acceptable and RAI 3.1.2.1-9, Part 2, is resolved. However, the staff seeks confirmation as to whether or not the RV internal lower support and lower support plate columns are fabricated from CASS materials and are within the scope of the AMRs identified in the bullets above (i.e., within the scope of AMR Item 8 of LRA Table 3.1-1, AMR Item 33 of LRA Table 3.1-1, and AMR Item 14 of LRA Table 3.1-2). This is Confirmatory Item 3.1.2.1-3, Part 2.

The applicant provided its response to Confirmatory Item 3.1.2.1-3, Part 2, in a letter dated September 16, 2003. In this response, the applicant clarified that only the upper support tube base, lower support plate columns, and bottom mounted instrumentation column cruciform are fabricated from CASS. The applicant clarified that the lower support column forging is fabricated from austenitic stainless steel and that the AMRs for this forging are given in AMRs Items 8 and 33 of LRA Table 3.1-1. The applicant confirmed that the lower support forging is not within the scope of AMR Item 14 of LRA Table 3.1-2 because the component is not fabricated from CASS. Since the applicant has provided the clarifications requested by the staff relative the CASS RV internal components, the staff consider Confirmatory Item 3.1.2.1-3, Part 2, to be resolved, and Confirmatory Item 3.1.2.1-3, Part 2 is closed.

<u>Item 32—Crack initiation and growth due to SCC, PWSCC, and IGSCC in steam generator upper and lower heads, tubesheets, and primary nozzles and safe ends—applicable GALL-2 item for Westinghouse recirculating SGs is IV.D1.1-i</u>

In AMR Item 32 of LRA Table 3.1-1, the applicant evaluates whether crack initiation and growth due to SCC, PWSCC, or intergranular stress corrosion cracking (IGSCC) is an applicable aging effect for the SG upper and lower heads, tubesheets, and primary nozzles and their safe-ends. The corresponding AMR is given in commodity group item IV.D1.1-i of GALL, Volume 2. The commodity group includes the bimetallic nickel-based alloy welds used to weld the nozzles to the SG shell and their safe ends to the primary RCS piping. The applicant identifies that the scope of GALL Item IV.D1.1-i includes SG primary nozzles and their safe ends to the SG shell (GALL component IV.D1.1.9) but states that it conservatively added the SG manway insert and SG lower head cladding to this commodity group because the components are fabricated from stainless steel. The applicant credits the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program and the Water Chemistry Program with managing crack initiation and growth due to SCC, PWSCC, and IGSCC in these components. This is consistent with the AMPs recommended in GALL for managing these aging effects. In its review of AMR Item 32 of LRA 3.1-1, the staff determined that the description in the discussion section of AMR Item 32 was consistent with guidance provided in the staff's corresponding AMRs in commodity group item IV.D1.1-i. The staff evaluates the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program and the Water Chemistry Program in Section 3.0.3 of this SER. Based on its evaluation, the staff concludes that AMR Item 32 of LRA Table 3.1-1 is acceptable because AMR Item 32 is consistent with GALL IV.D1.

<u>Item 33—Crack initiation and growth due to SCC and IASCC in Vessel Internals other than Westinghouse baffle/former bolts—applicable GALL-2 items are IV.B2.1-a, IV.B2.1-e, IV.B2.1-i, IV.B2.2-a, IV.B2.2-d, IV.B2.3-1, IV.B2.4-1, IV.B2.5-a, IV.B2.5-e, IV.B2.5-k, and IV.B2.6-a</u>

AMR Item 33 of LRA Table 3.1-1 evaluates whether or not crack initiation and growth due to SCC and IASCC are applicable aging effects for RV internals other than the baffle bolts. The corresponding AMRs are given in commodity group items IV.B2.1-a, IV.B2.1-e, IV.B2.1-i, IV.B2.2-a, IV.B2.2-d, IV.B2.3-1, IV.B2.4-1, IV.B2.5-a, IV.B2.5-e, IV.B2.5-k, and IV.B2.6-a of GALL, Volume 2. The applicant clarifies that the scope of this AMR includes the bottom mounted instrumentation (BMI) columns, BMI column cruciforms, diffuser plate, head and vessel alignment pins, head cooling spray nozzles, secondary core support, and upper instrument column, conduit, and supports and that crack initiation and growth is an applicable aging effect for these components. The applicant clarifies that the scope of this AMR does not include the rod cluster control assembly guide tube support pins because they do not serve an intended function as defined in 10 CFR 54.4. The applicant credits the PWR Vessel Internals Program and the Water Chemistry Program with managing SCC and IASCC in these components. In its review of AMR Item 33 of LRA Table 3.1-1, the staff determined that the description in the discussion section of the AMR was consistent with guidance provided in the staff's corresponding AMRs in commodity group items IV.B2.1-a, IV.B2.1-e, IV.B2.1-i, IV.B2.2-a, IV.B2.2-d, IV.B2.3-1, IV.B2.4-1, IV.B2.5-a, IV.B2.5-e, IV.B2.5-k, and IV.B2.6-a of GALL, Volume 2. The staff evaluates the Water Chemistry Program in Section 3.0.3 of this SER. The staff evaluates the PWR Vessel Internals Program in Section 3.1.2.3.4 of this SER. Based on this analysis, the staff concludes that AMR Item 33 of LRA Table 3.1-1 is acceptable and that no further evaluation is necessary.

<u>Item 34—Loss of material due to wear in RV closure studs and stud assembly—applicable GALL-2 item is IV.A2.1-d</u>

AMR Item 34 of LRA Table 3.1-1 (page 3.1-29 of the LRA) evaluates whether or not loss of material due to wear is an applicable aging effect for RV closure studs. The corresponding AMR is given in commodity group item IV.A2.1-d of GALL, Volume 2. In this AMR, the applicant concludes that loss of material due to wear is an applicable aging effect for the RV closure studs and credits the Reactor Vessel Head Closure Studs Program with managing this aging effect. In its review of AMR Item 34 of LRA Table 3.1-1, the staff determined that the description in the discussion section of the AMR was consistent with guidance provided in the staff's corresponding AMRs in commodity group item IV.A2.1-d of GALL, Volume 2. The staff evaluates the Reactor Vessel Head Closure Studs Program in Section 3.1.2.3.1 of this SER. Based on this analysis, the staff concludes that AMR Item 34 of LRA Table 3.1-1 is acceptable and that no further evaluation is necessary.

<u>Item 35—Loss of preload due to stress relaxation in Westinghouse upper and lower RV internal assemblies—applicable GALL-2 items are IV.B2.1-d, IV.B2.1-k, IV.B2.5-h, and IV.B2.5-i</u>

AMR Item 35 of LRA Table 3.1-1 (page 3.1-29 of the LRA) evaluates whether or not loss of preload due to stress relaxation is an applicable aging effect for bolted or fastened components in the RV internal upper and lower assemblies. The corresponding AMRs are given in commodity group items IV.B2.1-d, IV.B2.1-k, IV.B2.5-h, and IV.B2.5-i of GALL, Volume 2, which include the upper internals assembly hold-down spring (GALL component IV.B.1.7), upper internals assembly support column bolts (GALL component IV.B2.1.3), lower internals assembly support column bolts (GALL component IV.B2.5.5), and lower internals assembly clevis insert bolts (GALL component IV.B2.5.7). In this AMR, the applicant states that loss of preload due to stress relaxation is an applicable aging effect for these components, but clarifies that the AMPs credited for managing this aging effect in the components are slightly different from those recommended in the commodity group items listed above. The applicant states that the actual AMR for evaluating loss of preload in these components is given in AMR Item 15 of LRA Table 3.1-2.

In RAI 3.1.2.1-10, the staff asked the applicant to confirm that this item is not consistent with GALL and should not be included in Table 3.1-1, Item 35, but rather is appropriately addressed by the AMR stated in Item 15 of Table 3.1-2 of the application. The staff also asked the applicant to confirm that Item 35 of LRA Table 3.1-1 is redundant with Item 30 of LRA Table 3.1-1.

In its response to RAI 3.1.2.1-10, dated April 28, 2003, the applicant confirmed that AMR Items 30 and 35 of LRA Table 3.1-1, which deal with managing loss of preload/stress relaxation in fastened or bolted components in the RNP RV internal upper and lower assemblies, are redundant items. In its response to RAI 3.1.2.1-10, the applicant also confirmed that neither AMR Item 30 nor AMR Item 35 of LRA Table 3.1-1 are consistent with GALL because the applicant uses slightly different AMPs from those recommended by GALL for managing loss of preload in the upper and lower internal assembly components. The applicant therefore clarified that AMR Item 15 of LRA Table 3.1-2 provides the actual AMR for managing loss of preload/stress relaxation in the bolted or fastened components of the RV internal upper and lower assemblies. Because the applicant provided the clarification requested by the staff (i.e., the applicant clarified where the actual AMR assesses loss of preload in the fastened or bolted components of the RV internal upper and lower assemblies), this RAI is resolved. The staff evaluates AMR Item 15 of LRA Table 3.1-2 in Section 3.1.2.4.5 of this SER.

3.1.2.1.1 Conclusions

On the basis of its review the staff finds that the applicant's claim of consistency with GALL is acceptable, and that it is acceptable for the applicant to reference the information in the GALL Report for reactor system components. Therefore, on this basis, the staff concludes that, for those components that are managed consistent with the GALL Report, the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2 Aging Management Evaluations in the GALL Report That Are Relied On for License Renewal, For Which GALL Recommends Further Evaluation

For the component group items which the applicant has claimed consistency with GALL, and for which GALL recommends further evaluation, the staff reviewed the applicant's AMRs and evaluation to determine whether the applicant had adequately addressed the issues for which GALL recommended further evaluation.

The applicant provided its AMRs for its commodity group components that the applicant had claimed are consistent with GALL, but for which the SRP-LR and GALL recommend are in need of further evaluation in AMR Items 1–17 of Table 3.1-1 of the LRA. These AMRs correspond to the AMRs that are listed and defined in Rows 1–17 of Table 3.1-1 of this SER. The staff evaluates these AMRs in Sections 3.1.2.2.1 through 3.1.2.2.13 of this SER. In addition, as part of its review, the staff concluded that loss of material in the SG feedwater inlet ring and supports could be another AMR that should be given additional analysis. This additional AMR corresponds to the AMR that is defined in Row 18 in Table 3.1-1 of this SER. The staff evaluates this additional AMR item in Section 3.1.2.2.14 of this SER. Section 3.1.2.2.15 provides the staff's general conclusions for Section 3.1.2.2 of the SER.

3.1.2.2.1 Cumulative Fatigue Damage

According to Section 3.1.2.2.1 of the SRP-LR, thermal fatigue is a TLAA, as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff reviewed the evaluation of this TLAA in Section 4.3 of this SER, following the guidance in Section 4.3 of the SRP-LR. For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMRs for evaluating thermal fatigue of Class 1 RCS components are based on the guidelines in Section 3.1.2.2.1 of the SRP-LR and are identified in commodity group items IV.A2.1-b, IV.A2.1-e, IV.A2.2-c, IV.A2.3-c, IV.A2.4-a, IV.A2.5-d, IV.A2.8-a, IV.B2.1-c, IV.B2.1-h, IV.B2.1-m, IV.B2.2-c, IV.B2.2-f, IV.B2.3-d, IV.B2.4-g, IV.B2.5-d, IV.B2.5-j, IV.B2.5-p, IV.C2.1-a, IV.C2.1-b, IV.C2.2-a, IV.C2.2-b, IV.C2.2-c, IV.C2.3-a, IV.C2.3-d, IV.C2.4-a, IV.C2.4-d, IV.C2.5-a, IV.C2.5-d, IV.C2.5-e, IV.C2.5-f, IV.C2.5-q, IV.C2.5-t, IV.C2.5-w, IV.D1.1-a, IV.D1.1-b, IV.D1.1-h, and IV.D1.2-d of GALL, Volume 2, respectively.

Item 1 of LRA Table 3.1-1 provides the applicant's AMR entry for RCS components that are susceptible to thermal fatigue. Table 2.3-1 of the LRA refers to Item 1 of LRA Table 3.1-1 and is applicable to all Class 1 RCS components that serve a pressure boundary function, as well as for some of the RV internals that serve a support function for safety-related RV.

In RAI 3.1.2.2.1-1, the staff asked the applicant to provide a justification that a thermal fatigue analysis (TLAA) is not needed for those RV internals listed in Table 2.3-1 that are not referred to as being within the scope of Item 1 of LRA Table 3.1-1 (i.e., the AMR entry in Table 3.1-1 for RCS components subject to thermal fatigue). The staff clarified in the RAI that, if any of these RV internal components are passive components that are within the scope of license renewal and are susceptible to thermal fatigue during the period of extended operation, they must be included within the scope of AMR Item 1 of Table 3.1-1 of the LRA and analyzed within the scope of the TLAA for thermal fatigue, as described in Section 4.3 of the LRA. Section 4.3 of the LRA must then be revised accordingly.

In its response to RAI 3.1.2.2.1-1, dated April 28, 2003, the applicant identified the following RV internal components as within the scope of license renewal but not within the scope of the AMR on thermal fatigue of Class 1 RCS components—upper support column bolts, upper core plate alignment pins, lower support plate columns, clevis insert bolts, BMI columns, BMI column cruciform, diffuser plate, head cooling spray nozzle, secondary core support, and the upper instrumentation column, conduit, and supports. The applicant's basis for omitting these components from the scope of AMR Item of LRA 1 Table 3.1-1 is that the applicant only included the Class 1 components within the scope of the AMR if a thermal fatigue analysis existed within the CLB for any given Class 1 component at the plant. The applicant's reply indicates that 40-year thermal fatigue analyses were not performed for the components listed above. According to discussions provided in pertinent parts of Section IV.B2 of GALL, Volume 2 (such as GALL commodity group IV.B2.1-c), RV internal components only have to be included within the scope of an AMR on thermal fatigue of Class 1 components if a fatigue analysis for the components has been performed for the current operating period. The staff concludes that the applicant's basis for omitting these components from the scope of AMR Item 1 of LRA Table 3.1-1 is acceptable because it is consistent with the basis mentioned in Section IV.B2 of GALL, Volume 2, for including or excluding components within the scope of an AMR on thermal fatigue of ASME Class 1 components. RAI 3.1.2.2.1-1 is resolved.

In AMR Item 1 of Table 3.1-1, therefore, the applicant has credited a TLAA for thermal fatigue, as evaluated in accordance with 10 CFR 54.21(c), as the basis for managing thermal fatigue-induced cracking for the components within the scope of the AMR during the extended period of operation for RNP. In its discussion on the TLAA on thermal fatigue, the applicant stated that the TLAA is based on the time-limited assumptions for thermal fatigue that were defined in the CLB for the facility. The applicant's AMR for fatigue of the RCPB components that are susceptible to thermal fatigue, and its proposal to use a TLAA as the basis for managing thermal fatigue in these components, is in agreement with the recommendations in Section 3.1.2.2.1 of the SRP-LR that a TLAA be used as the basis for managing thermal fatigue of ASME Class 1 RCS components. The applicant's AMR for the RCPB components that are susceptible to thermal fatigue is therefore acceptable to the staff. The guidelines for performing TLAAs on thermal fatigue are given in Section 4.3 of the SRP-LR. The applicant provides its TLAA for thermal fatigue of these components in Section 4.3 of the LRA for RNP. The staff evaluates this TLAA in Section 4.3 of this SER.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of cumulative fatigue damage for components in the reactor systems, as recommended in the GALL Report.

3.1.2.2.2 Loss of Material Due to Pitting and Crevice Corrosion

According to Section 3.1.2.2.2 of the SRP-LR, loss of material due to pitting and crevice corrosion could occur in the PWR SG shell assembly. The existing program relies on control of chemistry to mitigate corrosion and ISI to detect loss of material. The extent and schedule of the existing SG inspections are designed to ensure that flaws cannot attain a depth sufficient to threaten the integrity of the welds. However, according to NRC IN 90-04, Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," (January 26, 1990), if general corrosion pitting of the shell exists, the program may not be sufficient to detect pitting and corrosion. The GALL Report recommends augmented inspection to manage this aging effect. The staff review verifies that the applicant has proposed a program that will manage loss of material due to pitting and crevice corrosion by providing enhanced inspection and supplemental methods to detect loss of material and will ensure that the component intended functions will be maintained during the period of extended operation.

For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMR for evaluating loss of material due to pitting or crevice corrosion of the SG shells is based on the guidelines in Section 3.1.2.2.2 of the SRP-LR and is identified in commodity group item IV.D1.1-c of GALL, Volume 2.

The applicant's AMR evaluation for components in the SG assembly commodity group that may be susceptible to general corrosion, pitting corrosion, or crevice corrosion is given in AMR Item 2 of LRA Table 3.1-1. In this AMR item, the applicant included the carbon steel steam and feedwater nozzles in this commodity group because they are welded to the SG shell assembly; however, the applicant did not include the SG shell transition cones and their associated fabrication welds within the scope of AMR Item 2.

In RAI 3.1.2.2.2-1, the staff requested the applicant amend AMR Item 2 of LRA Table 3.1-1 to include these components. In its response to RAI 3.1.2.2.2-1, dated April 28, 2003, the applicant stated it did not take any exceptions to the corresponding analysis provided in commodity group item IV.D1.1-c of GALL, Volume 2, and that, therefore, the SG shell transition cones are within the scope of AMR Item 2 of LRA Table 3.1-1. Since the applicant's response clarifies that the SG shell transition cones are within the scope of the applicant's AMR, the staff concludes that the response to the RAI resolves the question of whether the scope of the AMR includes SG shell transitions; therefore, no amendment of the AMR is necessary.
RAI 3.1.2.2.2-1 is resolved.

In this AMR item, the applicant stated that the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program and the Water Chemistry Program will be used to monitor loss of material in the SG assembly components that can be induced by general corrosion, pitting corrosion, or crevice corrosion. This is in agreement with Item D1.1-c of GALL Table IV.D1 and is therefore acceptable to the staff.

The applicant's Water Chemistry and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Programs are given in Sections B.2.1 and B.2.2 of the LRA. The staff evaluates the capability of these programs to manage potential pitting and cracking in the SG transition cones and associated weld materials in Sections 3.0.3.3 and 3.0.3.2 of this SER, respectively. In particular, the scope of the staff's evaluation of the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program includes a review of the ability of NDE methods selected for the SG transition cone welds to distinguish between recordable indications resulting from flaws in the weld from those that would result from geometric irregularities in the weld profiles.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of loss of material due to pitting and cracking in the SG transition cones and associated weld materials for components in the reactor systems, as recommended in the GALL Report.

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement and Dimension Changes Due to Void Swelling

According to Section 3.1.2.2.3 of the SRP-LR, loss of fracture toughness due to neutron irradiation embrittlement in RV base metal and weld materials is managed as a TLAA, as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff reviews the evaluation of this TLAA separately following the guidance in Section 4.2 of the SRP-LR. The results of the staff's review can be found in Section 4.2 of this SER. For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMRs for evaluating loss of fracture toughness due to neutron irradiation embrittlement in RV base metal and weld materials are based on the guidelines in Section 3.1.2.2.3 of the SRP-LR and are identified in commodity group items IV.A2.3-a and IV.A2.5-a of Table IV.A2 of GALL, Volume 2, respectively.

The TLAAs for neutron irradiation of RV shell materials are based on the following NRC regulations:

- 10 CFR 50.61 for protecting the RV against pressurized thermal shock events
- 10 CFR Part 50, Appendix G, Section IV.A.1, for maintaining adequate ductility (upper shelf energy) in RV materials
- 10 CFR Part 50, Appendix G, Section IV.A.2, for establishing the pressure-temperature limits for the reactor coolant system through the expiration of the extended period of operation

In AMR Item 3 of LRA Table 3.1-1, the applicant states that loss of fracture toughness is an applicable effect for ferritic Class 1 pressure vessel components that have amassed neutron fluences in excess of 1×10^{17} n/cm^2, and that a TLAA, performed in accordance with 10 CFR Part 50, Appendix G, and Regulatory Guide (RG) 1.99 will be used to manage this aging effect in these components. The staff uses 1×10^{17} n/cm^2 as the threshold for neutron irradiation embrittlement of ferritic materials in the RCS. The RV components in the beltline region of the RV are normally the only RCS components whose fluences are expected to exceed this threshold.

In RAI 3.1.2.2.3-1, the staff asked the applicant to clarify whether the pressured thermal shock (PTS), upper shelf energy (USE), and pressure-temperature (P-T) limit assessments discussed in column 5 of AMR Item 3 of LRA Table 3.1-1 will be performed in accordance with the following requirements:

- the evaluation criteria requirements and calculational method requirements of 10 CFR 50.61 for calculating RT_{PTS} for the RV beltline materials (i.e., materials with amassed neutron fluences in excess of 1 x 10^{17} n/cm^2) to demonstrate that they will have adequate protection against PTS events through the extended period of operation for RNP

- the requirements of 10 CFR Part 50, Appendix G, Section IV.A.2, for generating the P-T limits for the RCS through the expiration of the extended period of operation

- the requirements of 10 CFR Part 50, Appendix G, Section IV.A.1, for demonstrating that the RV beltline materials will have adequate levels of USE through the expiration of the extended period of operation[3], including the need to perform an appropriate equivalent margins analysis should the applicant determine that the USE value for any of the RV beltline materials is below 50 ft-lbs prior to the expiration of the extended period of operation for RNP

In its response to RAI 3.1.2.2.3-1, along with the information provided in the applicant's responses to RAIs 4.2.1-1; 4.2.2-1, Parts 1 and 2; 4.2.2.3-1; and 4.2.3-1, the applicant clarified that the RNP assessments for PTS, USE, and P-T limits will be conducted in accordance with the pertinent requirements and criteria of the following rules:

- 10 CFR 50.61 for performing the PTS assessments for the RV beltline materials

- 10 CFR Part 50, Appendix G, for performing the USE assessments for the RV beltline materials and the P-T limit calculations for the plant

The collective responses to RAIs 3.1.2.2.3-1; 4.2.1-1; 4.2.2-1, Parts 1 and 2; 4.2.2.3-1; and 4.2.3-1 confirm that any further changes to the RNP assessments for PTS, USE, and P-T limits which may occur in the future will continue to be performed in accordance with applicable regulations and requirements governing the assessments (i.e., 10 CFR 50.61 for PTS assessments and 10 CFR Part 50, Appendix G, for USE and P-T limit assessments). Since the applicant will continue to perform these assessments in accordance with the appropriate requirements, the staff concludes that RAI 3.1.2.2.3-1 is resolved.

The staff's evaluation of the TLAA for neutron irradiation embrittlement is given in Section 4.2 of this SER. Because the applicant has performed a TLAA for the RV beltline materials that are susceptible to neutron irradiation embrittlement, and because the applicant has clarified that the respective TLAAs for PTS, USE, and P-T limits are in accordance with the applicable requirements of 10 CFR 50.61 and Sections IV.A.1 and IV.A.2 of 10 CFR Part 50, Appendix G, the staff concludes that the applicant's AMR for the RV beltline materials, as described in Item 3 of the application and supplemented by the applicant's response to RAI 3.1.3.1.2.3-1, is in agreement with Item A2.5-a of Table IV.A2 of GALL, Volume 2, and is therefore acceptable.

According to Section 3.1.2.2.3 of the SRP-LR, loss of fracture toughness due to neutron

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[3]This requirement addresses the need to perform an appropriate equivalent margins analysis should the applicant determine that the USE value for any of the RV beltline materials is below 50 ft-lbs prior to the expiration of the extended period of operation for RNP.

irradiation embrittlement could occur in the RV. The Reactor Vessel Materials Surveillance Program monitors neutron irradiation embrittlement of the RV. Reactor vessel surveillance programs are plant-specific, depending on matters such as the composition of limiting materials, availability of surveillance capsules, and projected fluence levels. In accordance with 10 CFR Part 50, Appendix H, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation. The GALL Report recommends further evaluation of the Reactor Vessel Materials Surveillance Program for the period of extended operation. The staff concludes that the applicant has proposed an adequate reactor vessel materials surveillance program for the period of extended operation. For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMRs for evaluating loss of fracture toughness due to neutron irradiation embrittlement in RV base metal and weld materials are based on the guidelines in Section 3.1.2.2.3 of the SRP-LR and are identified in commodity group items A2.3-b and A2.5-c of Table IV.A2 of GALL, Volume 2, respectively.

In AMR Item 4 of LRA Table 3.1-1, the applicant states that the loss of fracture toughness is an applicable aging effect for the RV beltline shell, nozzle, and weld materials, and that the RNP Reactor Vessel Surveillance Program, together with the TLAA analyses discussed earlier, is used to manage the aging effects of reduction of fracture toughness due to neutron irradiation embrittlement for the RV beltline shell and welds. The applicant states that the Reactor Vessel Surveillance Program provides sufficient material data and neutron dosimetry information to predict irradiation embrittlement at the end of the period of extended operation and to determine the need for operating restrictions to preserve RV fracture toughness. The applicant further states that the nozzle and nozzle weld materials were evaluated and determined not to be controlling based on fracture toughness analyses. In addition, the applicant states that RNP has an active Reactor Vessel Surveillance Program with scheduled withdrawals extending into the license renewal period and that the surveillance capsule withdrawal schedule provides for adequate vessel materials surveillance for the period of extended operation. The applicant therefore concluded that aging management of this component/commodity group is consistent with the GALL Report. The RNP Reactor Vessel Surveillance Program is described in Section B.3.11 of the LRA.

The applicant's AMR for the RV beltline shell, nozzle, and weld materials is in agreement with the corresponding AMR for these materials in Items IV.A2.3-b and IV.A2.5-c of Table IV.A2 of GALL, Volume 2, and is therefore acceptable to the staff. The staff evaluates the capability of the RNP Reactor Vessel Surveillance Program to manage loss of fracture toughness in the RV beltline materials in Section 3.1.2.3.6 of this SER.

According to Section 3.1.2.2.3 of the SRP-LR, loss of fracture toughness due to neutron irradiation embrittlement and dimensional changes due to void swelling can occur in Westinghouse and B&W baffle/former bolts. The SRP-LR states that, to manage these aging effects, the need for a plant-specific AMP is to be evaluated, and that the applicant is to propose a plant-specific AMP for managing these aging effects or is to indicate that it will participate in the industry programs for investigating the inspection methods and acceptance criteria that will be necessary for aging management. Otherwise, the applicant is to provide the basis for concluding that void swelling is not an issue for the plant's baffle/former bolts. For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMRs for evaluating loss of fracture toughness due neutron irradiation and dimensional changes due to void swelling in Westinghouse and B&W baffle/former bolts are based on the guidelines in

Section 3.1.2.2.3 of the SRP-LR and are identified in commodity group items B2.4-d and B2.4-f of Table IV.B2 of GALL, Volume 2, respectively.

In AMR Item 5 of LRA Table 3.1-1, the applicant states that loss of fracture toughness due to neutron irradiation embrittlement and void swelling are applicable effects for the RNP baffle/former bolts and that both of these aging mechanisms will be managed by the PWR Vessel Internals Program. In the AMR, the applicant states that it will continue to participate in industry programs whose objectives include the investigation of aging effects applicable to baffle/former bolts and identification of appropriate AMPs and aging management activities to manage these effects. The applicant states that it will incorporate appropriate and applicable surveillance techniques as enhancements to the aging management activities that are proposed to manage these effects in the RNP baffle/former bolts. The applicant's AMR for the RNP baffle/former bolts is in agreement with the corresponding AMRs in Items B2.4-d and B2.4-f of Table IV.B2 of GALL, Volume 2, and is therefore acceptable to the staff. The applicant provides its description of the PWR Vessel Internals Program in Section B.4.3 of the LRA. The staff evaluates the capability of this program to manage loss of fracture toughness due to neutron irradiation embrittlement and void swelling in the RNP baffle/former bolts in Section 3.1.2.3.4 of this SER.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of loss of fracture toughness due to neutron irradiation embrittlement and dimensional changes due to void swelling for the RV and its internal components in the reactor systems, as recommended in the GALL Report.

3.1.2.2.4 Crack Initiation and Growth Due to Thermal and Mechanical Loading or Stress-Corrosion Cracking

According to Section 3.1.2.2.4 of the SRP-LR, crack initiation and growth due to thermal and mechanical loading or SCC, including IGSCC, could occur in small bore RCS and connected system piping less than nominal pipe size (NPS) 4.

The existing program relies on ASME Section XI ISI and on control of water chemistry to mitigate SCC. The GALL Report recommends that a plant-specific destructive examination or an NDE that permits inspection of the inside surfaces of the piping be conducted to ensure that cracking has not occurred and that the component intended function will be maintained during the extended period. The AMPs should be augmented by verifying that service-induced weld cracking is not occurring in the small bore piping less than NPS 4, including pipe, fittings, and branch connections. A one-time inspection of a sample of locations is an acceptable method to ensure that the aging effect is not occurring and the component's intended function will be maintained during the period of extended operation. GALL Chapter XI.M32, One-Time Inspection", contains an acceptable verification method.

The GALL Report recommends that the inspection include a representative sample of the system population, and, where practical and prudent, focus on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. For small bore piping, actual inspection locations should be based on physical accessibility, exposure levels, NDE examination techniques, and locations identified in IN 97-46, Unisolable Crack in High-Pressure Injection Piping." Combinations of NDE, including visual, ultrasonic, and surface techniques, are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR Part 50, Appendix B. For small bore piping less than NPS 4, including pipe, fittings, and branch connections, a plant-specific destructive examination or NDE that permits inspection of the inside surfaces of the piping should be conducted to ensure that cracking has not occurred. Followup of unacceptable inspection findings should include expansion of the inspection sample size and locations.

The inspection and test techniques prescribed by the program should verify any aging effects because these techniques, used by qualified personnel, have been proven effective and consistent with staff expectations. The staff's review confirms that the program includes measures to verify that unacceptable degradation is not occurring, thereby validating the effectiveness of existing programs or confirming that there is no need to manage aging-related degradation for the period of extended operation. If an applicant proposes a one-time inspection of select components and susceptible locations to ensure that corrosion is not occurring, the reviewer verifies that the proposed inspection will be performed using techniques similar to ASME Code and American Society for Testing and Materials (ASTM) standards, including visual, ultrasonic, and surface techniques, to ensure that the component's intended function will be maintained during the period of extended operation.

For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMRs for evaluating crack initiation and growth in the Class 1 RCS small bore piping (i.e., pipe sizes less than NPS 4) are based on the guidelines in Section 3.1.2.2.4 of the SRP-LR and are identified in commodity group items IV.C2.1-g and IV.C2.2-h of Table IV.C2 of GALL, Volume 2, respectively.

In AMR Item 6 of Table 3.1-1 of the RNP LRA, the applicant states that crack initiation and growth induced by SCC and/or thermal or mechanical loading are applicable aging effects for small bore piping in the RCS that is exposed to chemically treated borated water and that these aging effects will be managed by the following two AMPs:

(1) implementation of the RNP Water Chemistry Program that meets the recommended program attributes of GALL XI.M2, Water Chemistry Program"

(2) implementation of a One-Time Inspection Program for small bore piping that meets the recommended program attributes of GALL XI.M32, One Time Inspection"

The small bore components covered by the scope of AMR Item 6 of LRA Table 3.1-1 include the RNP RV flange leakage detection lines.

In RAI Item 3.1.2.2.4-1, the staff informed the applicant that its discussion section for AMR Item 6 in LRA Table 3.1-1 did not appear to credit the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program as one of the AMPs for managing crack initiation and growth in RCS small bore piping components less than 4 NPS in size and that, to be consistent with AMR Item IV.C2-g in GALL, Volume 2, the applicant should credit the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program as one of three programs for managing crack initiation and growth in RCS small bore piping components less than 4 NPS in size (i.e., in addition to the Water Chemistry Program and a one-time inspection for the small bore pipe that meets the program attributes described in GALL XI.M32). The staff asked the applicant to modify AMR Item 6 of LRA Table 3.1-1 to add the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program as one of the three programs used by RNP to manage crack initiation and growth in RCS small bore piping components less than 4 NPS in size. If not, the staff requested the applicant to provide a technical basis as to why the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program does not need to be credited with managing cracking in these components as well as an explanation as to why the AMR in AMR Item 6 of Table 3.1-1 should not have been included within the scope of Table 3.1-2 of the LRA.

In its response to RAI 3.1.2.2.4-1, dated April 28, 2003, the applicant gave the following basis for not crediting the ASME Section XI, Inservice Subsections IWB, IWC, and IWD Program for aging management in AMR 6.

The ASME Code, Section XI exempts 4 inch and under piping from volumetric examinations, but does require surface examinations. As such, the Section XI Program can be used to manage externally initiated cracking in small bore piping, but would not be considered effective for internally initiated cracking. In the SER for Generic Technical Report WCAP-14575A, the NRC notes that austenitic stainless steel components in Westinghouse NSSS loops are not susceptible to external cracking unless the outside surface comes into contact with halogens. RNP controls chemicals that might contact primary loop components to prevent this from occurring, and site operating experience affirms the effectiveness of these controls. Hence, externally initiated cracking is not considered an applicable aging effect, and the Section XI Program is not credited.

Since the Section XI Program is listed in GALL, but not credited by RNP, the pertinent AMR discussion in Item 6 of LRA Table 3.1-1 would be more appropriate in LRA Table 3.1-2.

The applicant is not crediting the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program for aging management of this line item because Section XI of the ASME Code does not require volumetric examinations of Class 1 pipe less than 4 inches in diameter, and on the implication that the NRC recommends a one-time volumetric examination of the small bore Class 1 piping components on the basis that the current ASME Section XI inspection criteria may not be sufficient to detect cracking in these welds prior to a failure of the components. However, Section XI of the ASME Code, as invoked by 10 CFR 50.55a, continues to require surface examinations of small bore Class 1 piping welds (less than 4 inches NPS) once every ISI interval and visual VT-2 leakage examinations of the components every RFO. The staff is concerned that the AMPs credited by the applicant for managing crack initiation and growth of small bore Class 1 piping may be used as a precedent for relieving the applicant of performing the required ASME ISI examinations for the small bore Class 1 piping welds during the period of extended operation for RNP. Therefore, the staff seeks confirmation that the applicant will continue to perform the ISI examinations of the small bore Class 1 piping that are required by Section XI of the ASME Boiler and Pressure Vessel Code during the period of extended operation for RNP. This is Confirmatory Item 3.1.2.2.4-1.

In its response to Confirmatory Item 3.1.2.2.4-1, dated August 14, 2003, the applicant confirmed that it would continue to conduct all applicable ISI inspections of the Class 1 small bore piping required by Section XI of the ASME Boiler and Pressure Vessel Code, unless relief is requested and granted by the staff under applicable provisions in 10 CFR 50.55a. Since the applicant response indicates that the applicant will continue to meet the inspection requirements for Class 1 small bore pipe, as required by 10 CFR 50.55a and Section XI of the

ASME Boiler and Pressure Vessel Code, during the period of extended operation for RNP, the applicant's response to Confirmatory Item 3.1.2.2.4-1 is acceptable. Confirmatory Item 3.1.2.2.4-1 is resolved.

The applicant will continue to do the ISI examinations required by Section XI for the small bore Class 1 piping during the extended period of operation, the staff concludes that the applicant has provided a reasonable basis for omitting the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program as one of the AMPs credited for managing cracking in the small bore Class 1 piping at RNP. RAI 3.1.2.2.4-1 is therefore resolved.

In its response to RAI 3.1.2.2.4-1, the applicant also clarified that, because RNP is not using the combination of AMPs recommended in commodity group item IV.C2-g of GALL, Volume 2, the AMR for this item would have been more appropriately addressed in LRA Table 3.1-2. Therefore, although the staff is evaluating AMR Item 6 of LRA Table 3.1-1 in this section of the SER, the staff is treating this AMR as if it were an AMR item that is designated by the applicant as inconsistent with the corresponding AMR in commodity group item IV.C2-g of GALL, Volume 2. The staff evaluates the ability of the program attributes for these AMPs to manage crack initiation and growth in the Class 1 small bore piping components in Sections 3.0.3.9.2 and 3.1.2.2.4 of this SER.

On the basis of its review of the AMR Item 6 of LRA Table 3.1-1, as modified by the information in the applicant's response to RAI 3.1.2.2.4-1, the staff finds that the applicant has adequately evaluated the management of crack initiation and growth due to thermal and mechanical loading or SCC for components in the reactor systems, as recommended in the GALL Report.

3.1.2.2.5 Crack Growth Due to Cyclic Loading

According to Section 3.1.2.2.5 of the SRP-LR, crack growth due cyclic loading could occur in the RV shell and RCS piping and fittings. Growth of intergranular separations (underclad cracks) in low-alloy or carbon steel heat-affected zones under austenitic SS cladding is a TLAA to be evaluated for the period of extended operation for all the SA 508 Class 2 forgings where the cladding was deposited with a high heat input welding process. The methodology for evaluating the underclad flaw should be consistent with the current well-established flaw evaluation procedure and criterion in the ASME Section XI Code. The GALL Report recommends further evaluation of programs to manage crack growth due to cyclic loading in the RV shell and RCS piping and fittings. The corresponding AMR for evaluating this form of crack growth in the RV shell and RCS piping and fittings is based on the guidelines in Section 3.1.2.2.5 of the SRP-LR and is identified in commodity group item IV.A2.5-b of Table IV.A2 of GALL, Volume 2.

In AMR Item 7 of Table 3.1-1 of the LRA, the applicant indicates that crack growth of potentially existing flaws in the ferritic portions (i.e., carbon steel or low-alloy steel portions) of the RV directly beneath the RV cladding (i.e., RV underclad cracking) is a potential aging effect requiring management and that a TLAA has been performed to manage this aging effect through the end of the extended period of operation for RNP. The applicant's AMR for managing underclad cracking in the RV is in agreement with the staff's corresponding AMR for commodity group item IV.A2.5-b of GALL, Volume 2, and is therefore acceptable to the staff. The applicant's TLAA for managing RV underclad cracking is given in Section 4.3 of the application. The staff evaluates this TLAA in Section 4.3.4 of this SER.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of crack growth due to cyclic loading for components in the reactor systems, as recommended in the GALL Report.

3.1.2.2.6 Changes in Dimension Due to Void Swelling

According to Section 3.1.2.2.6 of the SRP-LR, changes in dimension due to void swelling could occur in reactor internal components. The GALL Report recommends further evaluation to ensure that this aging effect is adequately managed. The RV internals receive a visual inspection (VT-3) according to Category B-N-3 of Subsection IWB of ASME Section XI. However, this inspection is not sufficient to detect the effects of changes in dimension due to void swelling. Therefore, GALL recommends that a plant-specific AMP be evaluated. The applicant should either provide the basis for concluding that void swelling is not an issue for the component, or provide a program to manage the effects of dimensional changes due to void swelling and the loss of ductility associated with such swelling. The staff verified that the applicant has either proposed a program to manage dimensional changes due to void swelling in the pressure vessel internal components or provided the basis for concluding that void swelling is not an issue. For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMRs for evaluating void swelling of the RV internal components are based on the guidelines in Section 3.1.2.2.6 of the SRP-LR and are identified in commodity group items B2.1-b, B2.1-f, B2.1-j, B2.2-b, B2.2-e, B2.3-b, B.2.4-b, B2.4-d, B2.5-b, B2.5-f, IV.B2.5-1 and B2.6-b of Table IV.B2 of GALL, Volume 2, respectively.

In AMR Item 8 of Table 3.1-1 to the LRA, the applicant identified that, with the exception of the neutron flux thimble guide tubes, the RV internals for RNP are potentially susceptible to the effects of void swelling. Void swelling is a high temperature/high irradiation phenomenon in which high neutron irradiation induces the formation of voids in RV internal materials. In AMR Item 8 of Table 3.1-1, the applicant stated that it continues to participate in industry programs designed to investigate and evaluate the aging effects, including void swelling for RV internals, and that it will incorporate the applicable results of industry initiatives related to void swelling into the PWR Vessel Internals Program. This approach conforms to one of the two recommended approaches in the AMRs for commodity group items IV.B2.1-b, IV.B2.1-f, IV.B2.1-j, IV.B2.2-b, IV.B2.2-e, IV.B2.3-b, IV.B.2.4-b, IV.B2.4-d, IV.B2.5-b, IV.B2.5-f, IV.B2.5-1 and IV.B2.6-b of Table IV.B2 of GALL, Volume 2.

The LRA appeared to omit void swelling as an applicable effect for the neutron flux thimble tubes because the thimble tubes are partly located outside of the RV and are not expected to experience excessive irradiation at elevated temperatures. In contrast, the AMR for commodity group item IV.B2.6-b of Table IV.B2 of GALL, Volume 2, identifies that void swelling is an applicable aging effect for Westinghouse-designed RV internal flux thimble guide tubes. Therefore, in RAI 3.1.2.2.6-1, Parts 1 and 2, the staff informed the applicant that its AMR for evaluating dimensional changes in the RNP RV internal neutron flux thimble guide tubes did not appear to be consistent with the corresponding assessment in GALL, Volume 2, and, in general, asked the applicant to discuss whether dimensional changes due to void swelling are considered to be an applicable aging effect for the RNP neutron flux thimble guide tubes. If so, the staff asked the applicant to discuss whether an AMR had been performed for managing this aging effect in the neutron flux thimble guide tubes.

In its response to RAI 3.1.2.2.6-1 (which provided one reply to address Parts 1 and 2 of the

RAI), dated April 28, 2003, the applicant clarified that the scope of AMR Item 8 of LRA Table 3.1-1 includes only those portions of the neutron flux thimble guide tubes that provide structural support to safety-related components and that are located internal to the RV. The applicant stated that dimensional changes due to void swelling is currently a topic under review by the industry and that, to manage this aging effect, CP&L has selected those RV internals that are projected to be subject to the highest radiation fluxes. The applicant stated that these components will act as predictors for other RV internal components. The applicant credits the PWR Vessel Internals Program with managing void swelling in RV internal components. The applicant stated that the PWR Vessel Internals Program (Section B.4.3 of the LRA) makes the following statement with respect to the management of void swelling in RV internals.

> The PWR Vessel Internals Program will incorporate the following enhancements that impact program elements for Scope of Program and Corrective Actions:
>
> - To address change in dimensions due to void swelling, RNP will continue to participate in industry programs to investigate this aging effect and determine the appropriate AMP.
> - To address baffle and former assembly issues, RNP will continue to participate in industry programs and will implement appropriate program enhancements to manage the aging effects associated with the Baffle and Former Assembly.
> - As Westinghouse Owner's Group (WOG) and EPRI Materials Reliability Project (MRP) research projects are completed, RNP will evaluate the results and factor them into the PWR Vessel Internals Program. The expected results include identification of components which are the most limiting and most susceptible and identification of appropriate inspection techniques.
> - RNP will implement an augmented inspection during the license renewal term. Augmented inspections, based on required program enhancements, will become part of the ASME Section XI program. Corrective actions for augmented inspections will be developed using repair and replacement procedures equivalent to those requirements in ASME Section XI.

This statement is reflected in Commitment No. 33 of Attachment II to CP&L Serial Letter No. RNP-RA\03-0031, dated April 28, 2003. Commitment No. 33 also includes a commitment to submit the augmented inspection plan for the RNP RV internal components to the NRC for review and approval 24 months prior to implementation of the augmented inspection for the RV internal components. The applicant is relying on the results of industry initiative studies on void swelling of RV internal components as its basis for determining whether void swelling needs to be managed during the license renewal period. The commitment to submit the augmented inspection plan to the staff for review and approval 24 months ahead of implementation will permit the staff time to determine whether void swelling is a relevant issue for the RV internal components of PWR-designed facilities and whether CP&L's proposed augmented inspection techniques for managing void swelling in the RNP RV internal components, including the internal portions of the neutron flux thimble guide tubes, are necessary and acceptable. This approach is consistent with the approach recommended in Section IV.B2 of GALL, Volume 2, for managing void swelling in RV internal components. Because the applicant's response to RAI 3.1.2.2.6-1, Parts 1 and 2, and the Commitment No. 33 of Attachment II to CP&L Serial Letter No. RNP-RA\03-0031 provide a clarification on how the applicant will manage void swelling in the RNP RV internal components, and because the approach is consistent with that recommended in Section IV.B2 of GALL, Volume 2, the staff concludes AMR Item 8 of the LRA is consistent with GALL and is acceptable. RAI 3.1.2.2.6-1, Parts 1 and 2, are resolved.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of changes in dimension due to void swelling for components in the reactor systems, as recommended in the GALL Report.

3.1.2.2.7 Crack Initiation and Growth Due to Stress-Corrosion Cracking or Primary Water Stress-Corrosion Cracking

According to Section 3.1.2.2.7 of the SRP-LR, crack initiation and growth due to SCC and PWSCC could occur in PWR core support pads (or core guide lugs), instrument tubes (bottom head penetrations), pressurizer spray heads, and SG instrumentation and drain nozzles. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed. The GALL Report recommends that a plant-specific AMP be evaluated because existing programs may not be capable of mitigating or detecting crack initiation and growth due to SCC. Acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 of the SRP-LR). The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects. For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMRs for evaluating crack initiation and growth due to SCC and PWSCC of PWR core support pads (or core guide lugs), instrument tubes (bottom head penetrations), pressurizer spray heads, and SG instrumentation and drain nozzles are based on the guidelines in Section 3.1.2.2.7 of the SRP-LR and are identified in commodity group items IV.A2.-f, IV.A2.6-a, IV.A2.7-a, IV.C2.5-j, and IV.D1.1-j of GALL, Volume 2, respectively.

In AMR Item 9 of Table 3.1-1 in the LRA, the applicant provides its AMR for the RNP core support pads, instrument tubes (bottom head penetrations), pressurizer spray heads, and SG instrument nozzles and drains and identifies that growth due to SCC and/or PWSCC is an applicable effects for these components.

The applicant's AMR for this commodity group states that the pressurizer spray head performs no license renewal intended functions at RNP, and that the SG instrument nozzles (GALL item D1.1.10) are not fabricated from Alloy 600 so they do not meet the criteria of this group. The applicant's AMR for this commodity group also states that the RPV flange leak detection line is fabricated from SS and is included in the category of small bore piping. Management of crack initiation and growth for this component is addressed in Item 6 for small bore SS piping, which is consistent with the GALL Report. The RNP core support pads and RV bottom head penetrations are fabricated of nickel-based alloy. The Water Chemistry Program is used to manage cracking from SCC for the support pads, and both the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program and the Water Chemistry Program are used to manage cracking from SCC for the bottom head penetrations. As these AMPs differ from the plant-specific AMP recommended by the GALL Report, aging management for these components is addressed in LRA Table 3.1-2, Items 9 and 10.

For the core support pads, RV bottom head instrumentation nozzles, pressurizer spray head, and SG instrumentation nozzles and drains, the issue is that existing programs, such as the Water Chemistry Program and/or the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program, may not be sufficient to manage SCC-induced or PWSCC-induced crack initiation and growth in these components. For the core support pads, the applicant evaluated the inconsistency with Section IV.A2.6-a of GALL, Volume 2, and provides the AMR for the components in Item 9 of Table 3.1.2-1 of the LRA. For the RV bottom head instrumentation tubes, the applicant evaluated the inconsistency with Section IV.A2.6-a of GALL, Volume 2, and provides the AMR for the components in Item 10 of Table 3.1.2-1 of the LRA. The staff evaluates the applicant's AMR for the RV core support pads in Section 3.1.2.4.5 of this SER. The staff evaluates the applicant's AMR for the RV bottom head instrumentation tubes in Section 3.1.2.4.4 of this SER.

In AMR Item IV.C2.5-j of GALL, Volume 2, the staff states that crack initiation and growth due to SCC or PWSCC are applicable aging effects for pressurizer spray heads made from Alloy 600 or CASS materials, and that a plant-specific AMP is to be proposed to manage these aging effects in the pressurizer spray heads. In the discussion section of AMR Item 9 of LRA Table 3.1-1, the applicant stated that the pressurizer spray head serves no function for license renewal, implying that the pressurizer spray head is not within the scope of license renewal and therefore no AMR of the pressurizer spray head is required. In RAI 3.1.2.2.7-1, Part 1, the staff asked the applicant to provide a revised AMR for the pressurizer spray head if the RNP pressurizer spray head were within the scope of license renewal. This AMR should include the AMPs that will be credited to manage SCC-induced/PWSCC-induced crack initiation and growth in the spray head and loss of fracture toughness if the pressurizer spray head were fabricated from CASS.

Based on this assessment, the staff concludes that aging management of the pressurizer spray head is not required and RAI 3.1.2.2.7-1 is resolved. Pursuant to 10 CFR 54.21(a)(1), the staff will require an AMR to be performed for the pressurizer spray head if the applicant is required by the staff to bring the components within the scope of license renewal as part of the applicant's resolution of RAI 2.3.1.3-1 by Confirmatory Item 2.3.1.3-1.

In AMR Item IV.D1.1-j of GALL, Volume 2, the staff identifies that crack initiation and growth due to SCC or PWSCC are applicable aging effects for SG instrumentation nozzles and recommends that a plant-specific management program be evaluated for managing these aging effects. In Item 9 of LRA Table 3.1-1, the applicant stated that because RNP SG instrument nozzles are not fabricated from Alloy 600, they were not included in this item. Therefore, in RAI 3.1.2.27-1, Part 2, the staff asked the applicant to either clarify where the AMR for the SG instrument and drain nozzles can be found or, if an AMR has not been performed for these components, provide an AMR for the SG instrument and drain line nozzles, including the materials of fabrication, applicable environments, applicable aging effects, and AMRs for the components. The staff also asked the applicant to include the AMR for the nozzles as a part of LRA Table 3.1-2.

In its response to RAI 3.1.2.2.7-1, Part 2, dated April 28, 2003, the applicant stated that the RNP design does not include SG instrumentation nozzles that are fabricated from Alloy 600. The applicant stated that, instead, the SG instrumentation nozzles at RNP are fabricated from carbon steel and, therefore, the AMR in commodity group item IV.D1.1-j, as evaluated relative to GALL component D1.1.10 (SG instrumentation nozzles), is not applicable relative to the RNP design. The staff's AMR in commodity group item IV.D1.1-j of GALL, Volume 2, is only applicable to SG instrumentation nozzles that are fabricated from Alloy 600. Since the SG instrumentation nozzles at RNP are fabricated from carbon steel containing a SS cladding, the staff concludes that the AMR in commodity group item IV.D1.1-j of GALL, Volume 2, is not applicable to the design of the RNP SG instrumentation nozzles. RAI 3.1.2.2.7-1 is therefore resolved.

The applicant evaluated crack initiation and growth of the SG primary side nozzles (including primary side instrumentation nozzles) as a result of thermal fatigue in AMR 1 of LRA Table 3.1-1. The staff's evaluation of AMR Item 1 of LRA Table 3.1-1 is provided in Section 3.1.2.2.1 of this SER. The applicant evaluated crack initiation and growth of the SG primary side nozzles (including primary side instrumentation nozzles) as a result of SCC, PWSCC, and/or IASCC in AMR Item 32 of LRA Table 3.1-1. The staff's evaluation of AMR Item 32 of LRA Table 3.1-1 is given in Section 3.1.2.1 of this SER. The applicant evaluated loss of material in the SG primary side nozzles (including primary side instrumentation nozzles) as a result of pitting, crevice corrosion, or general corrosion in AMR Item 5 of LRA Table 3.1-2. The staff's evaluation of AMR Item 5 of LRA Table 3.1-2 is given in Section 3.1.2.4.6.2 of this SER.

However, the staff seeks confirmation as to whether the welds used to join the SG instrumentation nozzles to the SG shells were fabricated using Alloy 600 weld material (i.e., Alloy 82/182 filler metals). If Alloy 600 weld materials were utilized, the staff requests that the applicant state whether the welds will be within the scope of and managed by the Nickel-Alloy Nozzles and Penetrations Program. This is Confirmatory Item 3.1.2.2.7-1.

In its response to Confirmatory Item 3.1.2.2.7-1, dated September 16, 2003, the applicant stated that the welds joining the carbon steel steam generator shell to the carbon steel instrumentation nozzles are not fabricated from Alloy 600 weld material. The staff finds that the Nickel-Alloy Nozzles and Penetrations Program would not be an appropriate AMP to manage the aging effects of the instrumentation nozzle welds because Alloy materials (i.e., Alloy 82/182 filler metals) are not used in the welds. However, the steam generator instrumentation nozzles and associated welds are being managed by other applicable AMPs as discussed above. The staff concludes that Confirmatory Item 3.1.2.2.7-1 is closed because the applicant has clarified that the welds joining the carbon steel steam generator shell to the carbon steel instrumentation nozzles are not made of Alloy 600 materials.

According to Section 3.1.2.2.7 of the SRP-LR, crack initiation and growth due to SCC could occur in PWR CASS RCS piping and fittings and the pressurizer surge line nozzle. The GALL Report recommends further evaluation of piping that does not meet either the reactor water chemistry guidelines of TR-105714, PWR Primary Water Chemistry Guidelines-Revision 3," November 1995, or the material guidelines of NUREG-0313, Revision 2, Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping." Acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 of the SRP-LR). The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects. For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMRs for evaluating crack initiation and growth due to SCC of CASS RCS piping and the pressurizer surge line nozzle are based on the guidelines in Section 3.1.2.2.7 of the SRP-LR and are identified in commodity group items IV.C2.1-e, IV.C2.2-g, IV.C2.4-b, and IV.C2.5-i of GALL, Volume 2, respectively.

In AMR Item 10 of Table 3.1-1 of the LRA, the applicant provided its AMR for the RNP CASS RCS piping and fittings and pressurizer surge line nozzle, and identified that growth due to SCC and/or PWSCC is an applicable effect for these components. However, the applicant qualified that the RNP pressurizer surge nozzle is not fabricated from CASS and is instead fabricated from carbon steel clad with SS. Therefore, in RAI 3.1.2.2.7-2, the staff asked the applicant to clarify whether an AMR had been performed for the pressurizer surge nozzle and its safe end and, if so, to state where the AMR was located in the application.

In its response to RAI 3.1.2.2.7, Part 2, dated April 28, 2003, the applicant stated that the AMRs for the pressurizer surge nozzle and its safe end are provided in the following AMR items:

1.1 AMR Item 1 of LRA Table 3.1-1 which assesses cracking of ASME Code Class 1 components resulting from thermal fatigue

1.2 AMR Item 24 of LRA Table 3.1-1 which assesses crack initiation and growth due to SCC, IGSCC, and cyclic loading in RV nozzle safe-ends, CRDM housings, and other RCS components

1.3 AMR Item 2 of LRA Table 3.1-2 which assesses loss of material from either pitting corrosion or crevice corrosion in RCS components

The staff's evaluation of AMR Item 24 of Table 3.1-1 is given in Section 3.1.2.1 of this SER. The staff's evaluation of AMR Item 2 of Table 3.1-2 is given in Section 3.1.2.4.2.1 of this SER. Since the applicant has provided the clarification requested by the staff, the staff considers RAI 3.1.2.2.7-2 to be resolved.

The applicant has included the RNP CASS RCP casing in this group and has credited the RNP Water Chemistry Program with managing SCC in the CASS RCP casing. The applicant stated that, according to the GALL Report, Section IV.C, with respect to SCC of CASS components, a plant-specific program is required unless certain conditions apply. One of the conditions is maintaining water chemistry in accordance with EPRI TR-105714, Revision 3 (or a more recent edition). The RNP meets this water chemistry requirement. Therefore, the aging management for CASS piping and RCP casing in the RCS is consistent with the GALL Report. AMR Item IV.C2.3-b of GALL, Volume 2, states that the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program should be used to manage SCC-induced crack initiation and growth in CASS RCP casings if monitoring and control of primary water chemistry is not being done in accordance with EPRI TR-105714 (Revision 3 or more recent editions of the guidelines), or if material selection for the casings has not been done according to criteria in NUREG-0313, Revision 2, for ensuring that the carbon alloying content for the casings is less than 0.035 percent and the delta-ferrite content for the casings is greater than 7.5 percent. Since the applicant's AMR for the RCP casings indicated that the primary water chemistry is maintained in accordance with the chemistry guidelines of EPRI TR-105714, Revision 3, the staff concludes that the AMR for the RCP casings is consistent with GALL and is therefore acceptable.

According to Section 3.1.2.2.7 of the SRP-LR, crack initiation and growth due to PWSCC could occur in PWR pressurizer instrumentation penetrations and heater sheaths and sleeves made of nickel alloys. The existing program relies on ASME Section XI ISI and on control of water chemistry to mitigate PWSCC. However, the existing program should be augmented to manage the effects of SCC on the intended function of nickel-alloy components. The GALL Report recommends that the applicant provide a plant-specific AMP or participate in industry programs to determine an appropriate AMP for PWSCC of Alloy 600 base metals and Alloy 182/82 welds. Acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 of the SRP-LR). The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects. For

Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMRs for evaluating crack initiation and growth due to PWSCC of PWR pressurizer instrumentation penetrations, heater sheaths, and heater sleeves made of nickel-based alloys are based on the guidelines in Section 3.1.2.2.7 of the SRP-LR and are identified in commodity group items IV.C2.5-k and IV.C2.5-s of GALL, Volume 2, respectively.

In AMR Item 11 of LRA Table 3.1-1, the applicant indicated that crack initiation and growth due to PWSCC is an applicable aging effect for pressurizer instrumentation penetrations and heater sheaths and sleeves, if the components are made of nickel-based alloys. However, in the discussion column for AMR Item 11, the applicant clarified that the RNP pressurizer instrument penetrations and heater sheaths and sleeves are made of SS, and therefore refers the actual AMR for these components is within the scope of AMR Item 24 of Table 3.1-1 of the LRA. The applicant credited both the Chemistry Program and the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program for managing crack initiation and growth due to PWSCC/SCC in the pressurizer instrumentation penetrations and heater sheaths and sleeves. The applicant stated that these programs are consistent with GALL for managing SCC-induced cracking in Class 1 austenitic SS components. The staff has confirmed that the applicant's AMR for the SS pressurizer instrumentation penetrations and heater sheaths and sleeves is consistent with the staff's corresponding AMR for pressurizer heater sheaths and sleeves given in AMR Item IV.C2.5-s of GALL, Volume 2. In addition, the staff confirmed that the Water Chemistry Program and ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program are acceptable for managing SCC-induced crack initiation and growth in these components. The staff concludes that the applicant's AMR for the SS pressurizer instrumentation penetrations and heater sheaths and sleeves is consistent with the GALL Report and is therefore acceptable.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of crack initiation and growth due to SCC or PWSCC for components in the reactor systems, as recommended in the GALL Report.

3.1.2.2.8 Crack Initiation and Growth Due to Stress-Corrosion Cracking or Irradiation-Assisted Stress Corrosion Cracking

According to Section 3.1.2.2.8 of the SRP-LR, crack initiation and growth due to SCC or IASCC could occur in baffle/former bolts in Westinghouse and B&W reactors. In this section of the SRP-LR, the staff identifies that VT-3 visual examinations of baffle/former bolts have not identified the presence of cracking in the bolts because cracking occurs at the juncture of the bolt head and shank which is not accessible for visual inspection. The staff also stated that recent UT examinations of the baffle/former bolts at several plants have identified cracking and that the industry is currently addressing the issue of baffle bolt cracking in the EPRI-MRP, Issues Task Group (ITG), including activities to determine, develop, and implement the necessary steps and plans to manage the applicable aging effects on a plant-specific basis. In the GALL Report, the staff recommends that further evaluation be performed to ensure that these aging effects are adequately managed. Acceptance criteria to manage SCC or IASCC in the baffle/former bolts are described in Branch Technical Position RLSB-1 (Appendix A.1 of the SRP-LR).

For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMRs for evaluating crack initiation and growth due to SCC or IASCC of Westinghouse-design baffle/former bolts is based on the guidelines in Section 3.1.2.2.8 of the SRP-LR and are identified in commodity group item IV.C2.4-c of GALL, Volume 2.

In AMR Item 12 of Table 3.1-1 of the LRA, the applicant states that SCC-induced and IASCC-induced crack initiation and growth are applicable aging effects for Westinghouse baffle/former bolts. The applicant credits the PWR Vessel Internals Program and the Water Chemistry Program to manage SCC-induced and IASCC-induced crack initiation and growth in the RNP RV internal baffle/former bolts. The applicant stated that it will continue to participate in industry-wide programs whose objectives include the investigation of aging effects that are applicable to PWR vessel internal components and the identification of appropriate AMP(s) for managing these effects, including those for the baffle/former bolts. The applicant indicated that it is committed to incorporate into the PWR Vessel Internals Program any additional aging management activities resulting from ongoing industry initiatives that are determined applicable for managing these aging effects and mechanisms. The applicant stated that new AMP activities, or other surveillance techniques, will be incorporated as enhancements to the aging management activities applicable to baffle/former bolts.

The applicant has stated that, in addition, the Water Chemistry Program has proven effective in managing cracking from SCC in general, as indicated in the GALL Report for various other RV internals components, and that, when taken in conjunction with the PWR Vessel Internals Program, as modified with appropriate enhancements to be identified by ongoing industry programs, the Water Chemistry Program will adequately manage these aging effects. This approach is consistent with the staff's corresponding AMR for baffle/former bolts given in Item IV.B2.4-b of GALL, Volume 2, and AMPs recommended by GALL Item IV.B2.4-b for managing SCC-induced and IASCC-induced crack initiation and growth in these components. The staff therefore concludes that the applicant's AMR for the RV internal baffle/former bolts is consistent with the GALL Report, and is therefore acceptable.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of crack initiation and growth due to SCC or IASCC for components in the reactor systems, as recommended in the GALL Report.

3.1.2.2.9 Loss of Preload Due to Stress Relaxation

According to Section 3.1.2.2.9 of the SRP-LR, the staff states that loss of preload due to stress relaxation could occur in baffle/former bolts in Westinghouse and B&W reactors. The staff's recommended guidance in Section 3.1.2.2.9 of the SRP-LR is that visual inspections (VT–3) should be augmented to detect relevant conditions of stress relaxation because only the heads of the baffle/former bolts are visible, thus, VT-3 visual examinations methods may not detect loss of preload (loosening) of the baffle/former bolts. The GALL Report therefore recommends that a plant-specific AMP be implemented to ensure that these aging effects are adequately managed. Acceptance criteria for the inspections are described in Branch Technical Position RLSB-1 (Appendix A.1 of the SRP-LR). For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMRs for evaluating loss of preload due to stress relaxation of Westinghouse-design baffle/former bolts are based on the guidelines in Section 3.1.2.2.9 of the SRP-LR and are identified in commodity group item IV.B2.4-h of GALL, Volume 2.

In AMR Item 13 of Table 3.1-1 of the LRA, the applicant stated that loss of preload due to stress relaxation is an applicable aging effect for Westinghouse baffle/former bolts. The applicant also stated that stress relaxation is a result of creep and/or irradiation-induced creep. The GALL Report calls for a plant-specific program to manage the effects of loss of preload/stress relaxation. The applicant credits both the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program and the PWR Vessel Internals Program to manage loss of preload from irradiation creep at RNP. The scope of the PWR Vessel Internals Program includes participation in industry-wide programs for managing aging effects in PWR internal baffle bolts and implementation of recommended augmented inspection activities as part of participation in such programs, as necessary. The applicant indicated that it will continue to participate in industry programs whose objectives include the investigation of aging effects applicable to baffle/former bolts and identification of appropriate AMP activities. The applicant stated that it will incorporate any aging management activities, or surveillance techniques, resulting from the ongoing industry programs, as required, to enhance the aging management activities that have been proposed to evaluate the baffle/former bolts. Based on the planned activities, aging management of loss of preload in baffle/former bolts is consistent with the GALL Report.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of the loss of preload due to stress relaxation for components in the reactor systems, as recommended in the GALL Report.

3.1.2.2.10 Loss of Section Thickness Due to Erosion

According to Section 3.1.2.2.10 of the SRP-LR, loss of section thickness due to erosion could occur in SG feedwater impingement plates and supports. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that this aging effect is adequately managed. Acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 of the SRP-LR). The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects. For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMR for evaluating loss of section thickness due to erosion of the SG feedwater impingement plates and supports is based on the guidelines in Section 3.1.2.2.10 of the SRP-LR and is identified in commodity group item IV.D1.1-e of GALL, Volume 2.

In AMR Item 14 of LRA Table 3.1-1, the applicant stated that the RNP SGs use feed rings with J-nozzles but that the feed rings perform no license renewal intended function. The applicant did not provide any AMP or aging effect associated with the feed rings in Table 3.1-1 of the LRA. Therefore, in RAI 3.1.2.2.10-1, the staff requested the applicant to clarify whether the feed ring and support need to be included in Table 3.1-1 of the RNP LRA.

In its response to RAI 3.1.2.2.10-1, the applicant stated that LRA Table 3.1-1, Item 14, is a review of the last line on page 8 of GALL, Volume 1, and refers to AMR in GALL commodity group IV.D1.1-e, as assessed relevant to GALL component IV.D1.1.6, "Feedwater Impingement Plate and Support." In its response to RAI 3.1.2.2.10-1, the applicant restated its position that the RNP SG feedwater inlet ring and support are not within the scope of license renewal, and are therefore not part of the commodity group for AMR Item 14 of LRA Table 3.1-1. Therefore, they are not required to be within the scope of AMR.

In its response to RAI 3.1.2.2.10-1, the applicant clarified that the feed ring and support in the

SGs are not within the scope of license renewal and therefore are not required to be within the scope of aging management. The applicant's response to RAI 2.3.1.6-1 provided the technical basis for concluding that the SG feedwater inlet rings and their structural supports are not within the scope of license renewal, as defined in 10 CFR 54.4. However, in Open Item 2.3.1.6-1, the staff questioned the applicant's technical basis for its determination on the scoping of the SG feedwater inlet rings and their structural supports, and requested further technical justification as to why the SG feedwater inlet rings and their structural supports are not within the scope of license renewal and are not subject to AMRs.

In its response to Open Item 2.3.1.6-1, dated September 16, 2003, the applicant included the feedwater distribution ring and J-nozzles in the scope of the license renewal application as discussed in Section 2.3.1.6 of this SER. The applicant identified its Water Chemistry Program in LRA Section B.2.2 to manage the aging effect of loss of material from erosion for the feedwater distribution ring, as shown in modified Item 6 of LRA Table 3.1-2. The applicant stated that the RNP Water Chemistry Program maintains strict controls on suspended solids in the feedwater system to assure that erosion of the feedwater components will be managed. The staff's evaluation of the applicant's Water Chemistry Program is discussed in Section 3.0.3.3 of this SER.

The applicant stated that the J-nozzles are fabricated of Inconel, and is resistant to loss of material due to erosion. However, the feedwater distribution ring is made of carbon steel, which the staff believes may be susceptible to loss of material due to erosion under certain adverse environments. The applicant has identified its One-Time Inspection Program in LRA Section B.4.4 to manage loss of material due to flow-accelerated corrosion in the feedwater distribution ring and J-nozzles. Although erosion is not the same as FAC, the visual inspection performed under the One-Time Inspection Program should verify whether erosion is an aging effect in the feedwater distribution ring. If erosion is present, the applicant will need to take corrective actions to mitigate and monitor such degradation in accordance with the One-Time Inspection Program. In addition, the applicant has implemented a steam generator secondary side inspection plan in accordance with NRC GL 97-06. The plan specifies visual inspections of the feedwater distribution ring and J-nozzles which will be carried over into the extended period of operation in accordance with 10 CFR 54.29(a). The additional information regarding the applicant's steam generator internal inspection of the feedwater distribution ring and J-nozzles is discussed in Section 3.1.2.2.14 of this SER.

The staff finds that the applicant's AMR of the feedwater distribution ring and J-nozzles, with respect to loss of section thickness (i.e., loss of material) due to erosion, is acceptable because the applicant has identified its Water Chemistry Program to manage this aging effect. In addition, the applicant has identified the One-Time Inspection Program to manage the loss of material due to flow-accelerated corrosion and has implemented a steam generator internal inspection plan. Both of these programs will adequately manage the loss of material due to erosion in the feedwater distribution ring and J-nozzles.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of the loss of section thickness due to erosion for the feedwater distribution ring and J-nozzles, as recommended in the GALL Report.

3.1.2.2.11 Crack Initiation and Growth Due to Primary Water Stress-Corrosion Cracking, Outer- Diameter Stress-Corrosion Cracking, or Intergranular Attack, Loss of Material

Due to Wastage and Pitting Corrosion, Loss of Section Thickness Due to Fretting and Wear, or Denting Due to Corrosion of Carbon Steel Tube Support Plate

In Section 3.1.2.2.11 of the SRP-LR, the staff identifies that crack initiation and growth due to PWSCC, outer-diameter stress-corrosion cracking (ODSCC), or intergranular attack (IGA), loss of material due to wastage and pitting corrosion, or deformation due to corrosion could occur in Alloy 600 components of the SG tubes, repair sleeves, and plugs. All PWR licensees have committed voluntarily to an SG degradation management program described in NEI 97-06, "Steam Generator Program Guidelines." The GALL Report recommends that an AMP based on the recommendations of NEI 97-06 guidelines, or some other alternate regulatory basis for SG degradation management, should be developed to ensure that this aging effect is adequately managed.

At present, the NRC staff does not plan to endorse NEI 97-06 or the detailed industry guidelines referenced therein. The staff is working with the industry to revise plant technical specifications to incorporate the essential elements of the industry's NEI 97-06 initiative as necessary to ensure that tube integrity is maintained. This would require implementation of programs to ensure that performance criteria for tube structural and leakage integrity are maintained, consistent with the plant design and licensing basis. NEI 97-06 provides guidance on programmatic details for accomplishing this objective. These guidelines apply to all degradation or damage mechanisms. However, these programmatic details would be outside the scope of the technical specifications.

As part of the NRC's Reactor Oversight Program, the NRC would monitor the effectiveness of these programs in terms of whether the bottom line goals of these programs are being met, particularly whether the tube structural and leakage integrity performance criteria are in fact being maintained. The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects for the period of extended operation.

For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMRs for evaluating these aging effects in the Alloy 600 SG tubes, repair sleeves, and plugs are based on the guidelines in Section 3.1.2.2.11 of the SRP-LR and are identified in commodity group items IV.D1.2-a, IV.D1.2-b, IV.D1.2-c, IV.D1.2-e, IV.D1.2-f, IV.D1.2-g, IV.D1.2-i, and IV.D1.2-j of GALL, Volume 2, respectively.

In Table 3.1-1 of the LRA, Item 15, the applicant identified (1) crack initiation and growth due to PWSCC, ODSCC, and/or IGA, (2) loss of material due to wastage and pitting corrosion, (3) loss of section thickness due to fretting and wear, and (4) denting due to corrosion at tube support plate intersections of the SG tubes, repair sleeves, and plugs as aging effects for these components.

The applicant stated that loss of material due to wastage and pitting corrosion owing to exposure to phosphate chemistry is not applicable because phosphate chemistry is not used at RNP. However, pitting remains a possible aging mechanism in accordance with the RNP AMR. The staff agrees with the applicant that pitting is a possible aging mechanism that should be considered, even though the mechanism has not occurred in the RNP SGs.

The applicant stated that Bulletin 88-02, "Rapidly Propagating Fatigue Cracks in Steam

Generator Tubes," is not applicable to RNP based on the SG design and support plate material. In Bulletin 88-02, the staff discussed a tube rupture event that occurred in the North Anna Unit 1 SGs. The cause of the tube rupture was determined to be high cycle fatigue in combination with denting at the upper tube support plate, as well as absence of effective antivibration bar support. The RNP replacement SGs are not Westinghouse Model 51 SGs which were used at North Anna at the time of the event. (North Anna has since replaced its SGs). The RNP replacement SGs, are Westinghouse Model 44F, which use the broached-hole configuration for the tube support plate which is made of SS. This design mitigates the potential for denting at the tube support plate. The staff agrees with the applicant that Bulletin 88-02 is not applicable to RNP SGs based on the difference in SG designs.

The applicant stated that, per the GALL Report, the effectiveness of the AMP for managing degradation in SG tubes and plugs is contingent on implementing the programmatic guidelines of NEI 97-06 in SGs. For RNP, a combination of the Steam Generator Tubing Integrity and Water Chemistry Programs will be used for management of potential cracking, loss of section thickness, loss of material, and denting for SG tubes and plugs. Per the guidelines of NEI 97-06, RNP technical specifications, Section 5.5.9, provide the requirements for SG degradation management. These requirements, including tube inspection scope and frequency, plugging, repair, and leakage monitoring, have been incorporated into plant administrative controls. The programs and guidelines for aging management of SG tubes and plugs at RNP are consistent with the GALL Report. In RAIs 3.1.2.2.11-1 and 3.1.2.2.11-2, the staff requested additional information from the applicant in order to confirm that the structural integrity of the SG tubes would be maintained during the extended period of operation for RNP.

In RAI 3.1.2.2.11-1, dated April 28, 2003, the staff specifically asked the applicant to provide the following information relative to the AMR provided in AMR Item 15 of LRA Table 3.1-1:

(a) clarification of the types of SG sleeves and plugs installed at RNP, if SG sleeves or plugs have been used in repair of SG tubes, including specification of the material of construction

(b) an expanded discussion of the current and past degradation mechanisms in the RNP replacement SGs and identification of the regions where tube degradation has occurred in the past

(c) if SG plugs are used as repair methods at RNP, a clarification as to whether CP&L has implemented the corrective actions to address age-related degradation mechanisms identified in pertinent generic communications on SG tube plug degradation, including NRC IN 89-65, "Potential for Stress Corrosion Cracking in Steam Generator Tube Plugs Supplied by Babcock and Wilcox;" NRC IN 89-33, "Potential Failure of Westinghouse Steam Generator Tube Mechanical Plugs;" NRC Bulletin No. 89-01, "Failure of Westinghouse Steam Generator Tube Mechanical Plugs," Supplements 1 and 2 to NRC Bulletin 89-01; and NRC IN 94-87, "Unanticipated Crack in Particular Heat of Alloy 600 Used for Westinghouse Mechanical Plugs for Steam Generator Tubes"

(d) a clarification as to whether the applicant is committed to implementing the recommendations in the NEI guideline document, NEI 97-06

In its response to RAI 3.1.2.2.11-1, the applicant stated that no sleeves have been installed in the RNP SGs. The degradation mechanisms in the SGs can be found in the applicant's response to RAI B.2.4-2b. The type of plugs currently installed in the RNP SGs can be found in the applicant's response to RAI 3.1.2.2.11-1c. The RNP has one SG tube that was plugged with Westinghouse Alloy 600 mechanical plugs supplied from heat number 4523 (Group 1 heat) that was the subject of NRC Bulletin 89-01. These plugs were subsequently repaired by installation of an Alloy 690 plug-in-plug. The applicant's commitment to NEI 97-06 can be found in its response to RAI B.2.4-3.

The staff finds that the applicant has satisfied the staff's concerns regarding the SG tube plugs discussed in the above NRC generic communications. The staff has also found the applicant's responses to RAI B.2.4-2 and RAI B.2.4-3 to be acceptable. On the basis of the above findings, the staff finds the applicant's response to RAI 3.1.2.2.11-1 acceptable and RAI 3.1.2.2.11-1 is resolved.

In Item 15 of LRA Table 3.1-1, the applicant stated that," Bulletin No. 88-02 has been determined to be not applicable to Robinson Nuclear Plant (RNP) based upon the SG design and support plate material." In Bulletin No. 88-02, "Rapidly Propagating Fatigue Cracks in Steam Generator Tubes," the staff reported an SG tube rupture event at North Anna Unit 1 which was caused by high cycle fatigue. In the bulletin, the NRC staff concluded that the following conditions could lead to a rapidly propagating fatigue failure (1) denting at the upper support plate, (2) a fluid-elastic stability ratio approaching that for the tube that ruptured at North Anna, and (3) absence of effective antivibration bar support. The staff requested more information regarding the applicability of RNP SGs with respect to Bulletin 88-02.

In RAI 3.1.2.2.11-2, the staff requested the applicant to discuss whether any of the three factors listed above could cause fatigue failure of the RNP SG tubes.

In its response to RAI 3.1.2.2.11-2, dated April 28, 2003, the applicant stated that RNP responded to NRC Bulletin No. 88-02 in a letter from Mr. R.B. Richey (CP&L) to Dr. J. Nelson Grace (NRC), Serial NLS-88-049, "Response to NRC Bulletin No. 88-02, Rapidly Propagating Cracks in Steam Generator Tubes," dated March 24, 1988. In the letter, the applicant stated that Bulletin No. 88-02 is not applicable to RNP, Unit 2, because Westinghouse Model 44 SG support plates were constructed of SS, rather than carbon steel as indicated in the Bulletin's For Action" statement. In addition, Westinghouse and CP&L have confirmed that the two significant contributors to high fluid-elastic stability ratio (as discussed in the Bulletin) are not in evidence at RNP, Unit 2.

The tube support plate design for the RNP replacement SGs was selected to minimize the potential for tube denting. The design is discussed in the RNP response to RAI 3.1.2.2.12-1. The aging mechanisms, corrective actions, and tube plugs of the RNP replacement SGs are discussed in more detail in the RNP response to RAI B.2.4-2. The staff finds the applicant's response to RAI 3.1.2.2.11-2 acceptable because the applicant has provided the technical basis to show that NRC Bulletin 88-02 does not apply to the RNP replacement SGs. RAI 3.1.2.2.11-2 is resolved.

Based on the staff's review of AMR Item 15 of LRA Table 3.1-1 and the applicant's responses to RAIs 3.1.2.2.11-1 and 3.1.2.2.11-2, the staff concludes that AMR Item 15 of LRA Table 3.1-1 is consistent with the corresponding AMR in commodity group items IV.D1.2-a, IV.D1.2-b, IV.D1.2-c, IV.D1.2-e, IV.D1.2-f, IV.D1.2-g, IV.D1.2-i, and IV.D1.2-j of GALL, Volume 2, and is therefore acceptable.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of crack initiation and growth due to PWSCC, ODSCC, or IGA, loss of material due to wastage and pitting corrosion, loss of section thickness due to fretting and wear, or denting due to corrosion of carbon steel tube support plate for components in the reactor systems, as recommended in the GALL Report.

3.1.2.2.12 Loss of Section Thickness (Loss of Material) Due to Flow-Accelerated Corrosion

According to Section 3.1.2.2.12 of the SRP-LR, loss of section thickness (loss of material) due to FAC could occur in tube support lattice bars made of carbon steel. The GALL Report recommends further evaluation of loss of section thickness due to FAC of the tube support lattice bars made of carbon steel. The GALL Report further recommends that a plant-specific AMP be evaluated and, on the basis of the guidelines of NRC Generic Letter 97-06, an inspection program for SG internals should be developed to ensure that this aging effect is adequately managed. The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects. Acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 of the SRP-LR). For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMR for evaluating loss of section thickness (loss of material) due to FAC of the tube support lattice bars is based on the guidelines in Section 3.1.2.2.12 of the SRP-LR and is identified in commodity group item IV.D1.2-h of GALL, Volume 2.

In AMR Item 16 of LRA Table 3.1-1, the applicant stated that the GALL Report indicates that this component/commodity group is applicable to CE SGs. Therefore, the applicant did not consider the AMR item to be applicable to the RNP application. The staff believes that loss of section thickness due to FAC could occur in SG tube support plates regardless of the vendor of the SG design. However, the susceptibility of tube support configurations to a loss of section thickness is also dependent on the type of support plate configuration. Operating experience has demonstrated that tube support configurations using lattice bar designs may be susceptible to loss of section thickness resulting from FAC. The staff therefore felt it was necessary to get additional clarification regarding the type of SG tube support configuration used in the RNP SGs, as well as whether the applicant considered this aging effect to be applicable to the SG tube support configuration used at RNP. Therefore, in RAI 3.1.2.2.12-1, the staff asked the applicant to provide confirmation that the tube support configuration used in the RNP SG designs is not a lattice bar and is instead a tube support plate that is fabricated from SS. In the RAI, the staff also asked the applicant to assess whether or not loss of material due to FAC and cracking are applicable aging effects for the SG tube support configuration component at RNP and to provide a technical basis for its conclusions.

In its response to RAI 3.1.2.2.12-1, the applicant stated that the design of the RNP SG tube support plates is available in NUREG-1004, "Safety Evaluation Report Related to Steam Generator Repair at H.B. Robinson Steam Electric Plant Unit No. 2," dated November 1983. Section 3.3.5 in NUREG-1004 discusses the design features of the quatrefoil tube support plates.

> To reduce the potential for tube denting, the tube support plate material has been changed from carbon steel to ferritic stainless steel in the RNP replacement SGs. Corrosion in the crevice

between the tube and tube support plate (notably in drilled-hole design) with SGs utilizing carbon steel tube support plates has led to denting of the SG tubing in that area. Alternative support plate materials have been evaluated, and SA-240 Type 405 ferritic stainless steel has been selected as the optimum material for this application. This material is ASME Code-approved. In addition, SA-240 has a low wear coefficient when paired with Inconel and has a coefficient of thermal expansion similar to carbon steel. Corrosion of SA-240 results in an oxide which has approximately the same volume as the parent material, whereas corrosion of carbon steel results in oxides which have a larger volume than the parent material. In addition to the tube support plates, the baffle plate will be constructed of SA-240 Type 405 stainless steel.

The quatrefoil tube support plate design used in the RNP replacement SGs consists of four flow lobes and four support lands. The lands provide support to the tube during operating conditions; the lobes allow flow around the tube. The quatrefoil design directs the flow along the tubes to minimize steam formation and chemical concentrations at the tube-to-tube support plate intersections. The quatrefoil support plate design has a lower pressure drop and results in higher average velocities along the tubes, minimizing sludge deposition. The combination of higher velocities in the support plate region and corrosion-resistant material should minimize the potential for support plate corrosion.

GALL Item IV.D1.2.2, tube support lattice, is not applicable to RNP because it is part of a CE design for SGs. The RNP has Westinghouse-designed Sgs. The tube support plates at RNP are similar to GALL Item IV.D1.2.4 (IV-D1.2-k), with the exception that the GALL item is carbon steel and the RNP tube support plates are fabricated from SS. The AMRs for the tube support plates in the RNP SGs are contained in Table 3.1-1, AMR Item 1, and Table 3.1-1, AMR Item 17.

In Table 3.1-1, AMR Item 17, the applicant stated that the tube support plates in the RNP SGs are fabricated of SS, not carbon steel. The applicant further stated that the GALL Report is not specific regarding the type of corrosion involved for this component/commodity group and that, at RNP, the AMR for this component identified cracking from SCC and loss of material from crevice corrosion, pitting corrosion, and erosion as applicable aging effects/mechanisms. The applicant stated that these effects/mechanisms are managed by a combination of the Steam Generator Tube Integrity Program and the Water Chemistry Program applicable to SGs, and that this is in agreement with AMPs cited for this component in commodity group item IV.D1.2-k of GALL, Volume 2. The applicant therefore concluded that the AMPs credited at RNP for managing loss of section thickness due to FAC are consistent with those recommended in the GALL Report. Therefore, while tube support plates of SS are not evaluated in GALL, the applicant stated that RNP will use the same combination of programs to manage the applicable aging effects.

FAC is an aging phenomenon that involves oxidation and erosion of carbon steel or low-alloy steel materials in systems that involve high velocity water or water/steam phases. Increasing amounts of chromium in a steel alloy reduces the susceptibility of the steel to FAC. Chromium-molybdenum steels and austenitic SSs are therefore resistant to FAC because they contain sufficient amounts of chromium in their alloys.

The staff finds the applicant's response to RAI 3.1.2.2.12-1 acceptable because GALL requires evaluation of FAC when using SG lattice bars made from carbon steel; the RNP SGs are designed with SS quatrefoil designs which would not be susceptible to FAC. Therefore, the applicant has provided an acceptable basis for concluding the that FAC is not an applicable aging effect for the quatrefoil design of the SGs at RNP, as would otherwise be recommended by the staff's evaluation in GALL commodity group IV.D1.2-k. RAI 3.1.2.2.12-1 is resolved.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of loss of section thickness due to FAC for the SG tube support plate configurations in the reactor systems, as recommended in the GALL Report.

3.1.2.2.13 Ligament Cracking Due to Corrosion

According to Section 3.1.2.2.13 of the SRP-LR, ligament cracking due to corrosion could occur in carbon steel components in the SG tube support plate. The GALL Report recommends further evaluation of ligament cracking due to corrosion in carbon steel components in the SG tube support plate. All PWR licensees have committed voluntarily to an SG degradation management program described in NEI 97-06, "Steam Generator Program Guidelines." The GALL Report recommends that an AMP based on the recommendations of the NEI 97-06 guidelines, or some other alternate regulatory basis for SG degradation management, should be developed to ensure that this aging effect is adequately managed.

At present, the NRC staff does not plan to endorse NEI 97-06 or the detailed industry guidelines referenced therein. The staff is working with the industry to revise plant technical specifications to incorporate the essential elements of the industry's NEI 97-06 initiative as necessary to ensure tube integrity is maintained. This would require implementation of programs to ensure that performance criteria for tube structural and leakage integrity are maintained, consistent with the plant design and licensing basis. NEI 97-06 provides guidance on programmatic details for accomplishing this objective. These guidelines apply to all degradation or damage mechanisms. However, these programmatic details would be outside the scope of the technical specifications.

As part of the NRC's Reactor Oversight Program, the NRC would monitor the effectiveness of these programs in terms of whether the bottom line goals of these programs are being met, particularly whether the tube structural and leakage integrity performance criteria are in fact being maintained. The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects for the period of extended operation.

The staff reviewed the applicant's proposed program on a case-by-case basis to ensure that an adequate program will be in place for the management of these aging effects. For Westinghouse-designed light-water reactors with recirculating SGs, the corresponding AMR for evaluating ligament cracking in carbon steel SG tube support plate components is based on the guidelines in Section 3.1.2.2.13 of the SRP-LR and is identified in commodity group item IV.D1.2-k of GALL, Volume 2.

The applicant stated that the GALL Report indicates that this component/commodity group is applicable to CE SGs, and is therefore not applicable to RNP. The staff believes that ligament cracking due to corrosion could occur in SG tube support plates depending on the type of support plate configurations and operating experience, regardless of the vendor. In RAI 3.1.2.2.12-1, the staff requested the applicant to clarify the type of tube support plate configuration used in the RNP SG designs and whether the RNP tube support plates are susceptible to ligament cracking, thereby requiring aging management for this aging effect. RAI 3.1.2.2.12-1 is applicable to the determination as to whether ligament cracking due to corrosion is an aging effect for the RNP SGs. In the RAI, the staff informed the applicant that the applicant's response to RAI 3.1.2.2.12-1 will provide information to resolve this issue.

Section 3.1.2.2.13 of the SRP-LR discusses ligament cracking that can occur in carbon steel components of the SG tube support plates. The applicant's response to RAI 3.1.2.2.12-1 indicates that the tube support plate configurations in the RNP SGs are fabricated from SS. The staff therefore concludes that ligament cracking is not an applicable aging effect for the SG tube support plate designs used at RNP.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of ligament cracking due to corrosion for SG tube support plate configurations in the reactor systems, as recommended in the GALL Report.

3.1.2.2.14 Loss of Material Due to Flow-Accelerated Corrosion

According to Section 3.1.2.2.14 of the SRP-LR, loss of material due to FAC could occur in the SG feedwater inlet rings and supports. The GALL Report recommends that a plant-specific AMP be evaluated to manage loss of material due to FAC in the feedwater inlet rings and supports. As noted in IN 90-04, IN 91-19, "Steam Generator Feedwater Distribution Piping Damage," and Licensee Event Report (LER) 50-362/90-05-01, this form of degradation has been detected only in certain CE System 80 SGs. The GALL Report recommends that a plant-specific AMP be evaluated because existing programs may not be capable of mitigating or detecting loss of material due to FAC. Acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 of the SRP-LR). The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects. However, Section 3.1.2.2.14 of the SRP-LR states that this AMR only applies to loss of material in CE-designed steam generators.

The applicant stated that the GALL Report indicates that this component/commodity group is applicable to CE SGs and that, therefore, it is not applicable to RNP. However, the staff believes that loss of material due to FAC could occur in SG feedwater inlet rings and their supports depending on the type of ring and support configurations and operating experience, regardless of the vendor.

In its response to RAI 2.3.1.6-1, the applicant provided its technical basis for concluding that the SG feedwater inlet rings and their structural supports, are not within the scope of license renewal, as defined in 10 CFR 54.4. However, in Open Item 2.3.1.6-1, the staff questioned the applicant's technical basis for its determination on the scoping of the SG feedwater inlet rings and their structural supports, and requested further technical justification as to why the SG feedwater inlet rings and their structural supports are not considered to be within the scope of license renewal, and are therefore not subject to AMRs.

In its response to Open Item 2.3.1.6-1, dated September 16, 2003, the applicant included the feedwater distribution ring and J-nozzles in the scope of the license renewal application; as discussed in Section 2.3.1.6 of this SER. As part of its AMR of these components, the applicant identified its One-Time Inspection program in LRA Section B.4.4 to manage the aging effect of loss of material due to FAC in the feedwater distribution ring, as shown in Item 19 of revised LRA Table 3.1-2. In the discussion section of Item 19, the applicant stated that it will perform a visual inspection of the feedwater ring and J-nozzles to confirm that an AMP is not required for the license renewal period. The one-time inspection will occur prior to the period of extended operation, as specified in the applicant's Commitment Number 34 as discussed in Appendix A of this SER.

The applicant replaced the feedwater ring and J-nozzles as part of the steam generator replacement in 1984. The J-nozzles are fabricated of Inconel and the feedwater distribution ring is made of carbon steel. The applicant stated that loss of material from FAC has not been detected in Westinghouse steam generators. However, the staff believes that the carbon steel feed ring may be susceptible to FAC under adverse conditions.

As specified in the OneTtime Inspection Program discussed in LRA B.4.4, when unacceptable results are identified during the inspection, the applicant will need to perform corrective actions, including monitoring of the degradation in the component such as the feedwater distribution ring and J-nozzles. The staff's evaluation of the applicant's One-Time Inspection Program is discussed in Section 3.0.3.9 of this SER.

Although the applicant did not identify an AMP to manage the aging effects in the feedwater ring and J-nozzles during the extended period of operation, the applicant does have an existing inspection program that will be carried over into the period of extended operation in accordance with 10 CFR 54.29(a). In 1997, the NRC issued GL 97-06, "Degradation of Steam Generator Internals," requesting licensees to provide a written report that includes inspection plans for the steam generator secondary side components, such as the feedwater distribution ring. GL 97-06 specifies that the plans include inspection scope, frequency, methods, and equipment.

In its response to GL 97-06 dated March 30, 1998 (ADAMS Accession Number ML98040702402), the applicant stated that an inspection plan was being developed to monitor degradation in the steam generator secondary side components, including erosion and corrosion in the feedwater distribution ring and J-nozzles. The applicant's inspection plan specifies that the feedwater nozzle inspection is to be conducted in accordance with the ASME Code, Section XI, inservice inspection specifications. The inspection plan specifies a visual inspection of the secondary side of one steam generator during each refueling outage. The inspection scope, frequency, and number of steam generators were to be adjusted as necessary in future refueling outages as a result of (1) site-specific or industry experience, (2) implementation of the secondary side steam generator component monitoring program contained in NEI 97-06, or (3) Westinghouse Owners Group reports for the Westinghouse Model 44F steam generators.

In the March 30, 1998, letter, the applicant stated that it inspected the feedwater J-nozzles on steam generator "B," including chemical analysis of chromium content, during Refueling Outage 15 in 1995. The applicant stated that it did not identify any degradation in the feedwater nozzles during Refueling Outage 15 or in previous inspections.

The staff finds that loss of material due to FAC in the RNP feedwater distribution ring and J-nozzles will be adequately managed because the applicant has identified the One-Time Inspection Program and implemented a steam generator internal inspection plan, as discussed in the applicant's response to GL 97-06. The latter program will be carried over into the extended period of operation, in accordance with 10 CFR 54.29(a), to manage the aging effects in the feedwater distribution ring and J-nozzles.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of loss due to FAC in the feedwater distribution ring and J-nozzles, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that there is reasonable assurance that this aging effect does not have to be managed during the period of extended operation.

3.1.2.2.15 Conclusions

The staff has reviewed the applicant's evaluation of the issues for which GALL recommends further evaluation for components in the reactor systems. On the basis of its review, the staff concludes that the applicant has provided sufficient information to demonstrate that the issues for which GALL recommends further evaluation have been adequately addressed, and that the subject aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3). In addition, the staff concludes that the applicant's UFSAR Supplements provide adequate descriptions of the programs credited with managing these aging effects, as required by 10 CFR 54.21(d).

3.1.2.3 Aging Management Programs (System-Specific)

This section evaluates the ability of the AMPs credited for aging management to manage the applicable aging effects identified in the AMRs for the RCS components that are within the scope of license renewal and are subject to AMRs. This evaluation first involved a review of the specific AMRs for a given RCS commodity group to identify the applicable aging effects and AMPs in the AMR analysis. A second review of the specific AMP was then done to ensure that the component or commodity group, and their applicable aging effects, were captured within the scope of the AMP. The staff then reviewed the AMP to determine if the proposed inspection methods for inspection-based AMPs, or mitigative strategies for mitigative/preventive-based AMPs, would be sufficient to manage the aging effects for which the AMPs were credited. The results of the staff's review are provided below.

The staff also reviewed the UFSAR Supplement summary descriptions, as given in Appendix A of the application, for the AMPs credited with managing aging in reactor system components to determine whether the program description adequately described the program and captured its intent.

The applicant credits 17 AMPs to manage the aging effects associated with components in the RNP RCS. Nine of the AMPs are credited to manage aging for components in the RCS and other system groups (common AMPs), while eight AMPs are credited with managing aging only for the RCS components. The following common AMPs are used for management of aging effects in RCS components:

- ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program (LRA Section B.2.1)
- Water Chemistry Program (LRA Section B.2.2)
- Boric Acid Corrosion Program (LRA Section B.3.2)
- Flow-Accelerated Corrosion Program (LRA Section B.3.3)
- Bolting Integrity Program (LRA Section B.3.4)

- Open-Cycle Cooling Water System Program (LRA Section B.3.5)
- One-Time Inspection Program (LRA Section B.2.5)
- Selective Leaching of Materials Program (LRA Section B.4.5)
- Preventive Maintenance Program (LRA Section B.3.18)

The staff's evaluation of the common AMPs that are credited with managing aging in reactor system components is provided in Section 3.0.3 of this SER.

The following eight RCS-specific AMPs are used for management of aging effects in RCS components:

- Reactor Head Closure Studs Program (LRA Section B.2.3)
- Steam Generator Tube Integrity Program (LRA Section B.2.4)
- Flux Thimble Eddy Current Inspection Program (LRA Section B.2.8)
- Reactor Vessel Surveillance Program (LRA Section B.3.11)
- Metal Fatigue of Reactor Coolant Pressure Boundary (Fatigue Monitoring Program) (LRA Section B.3.9)
- Nickel-Alloy Nozzles and Penetrations Program (LRA Section B.4.1)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (LRA Section B.4.2)
- Reactor Vessel Internals Inspection Program (LRA Section B.4.3)

The staff evaluates these RCS-specific AMPs in the subsections to SER Section 3.1.2.3 that follow.

3.1.2.3.1 Reactor Head Closure Studs Program

The applicant discusses its Reactor Head Closure Studs Program in Section B.2.3. of Appendix B of the LRA. The applicant credits this AMP with managing the aging effects that are applicable to the RNP RV head closure studs.

3.1.2.3.1.1 Summary of Technical Information in the Application

The applicant identifies that the Reactor Head Closure Studs Program is used to manage loss of material due to wear and loss of preload due to stress relaxation in RV head closure bolting materials. The applicant states that the Reactor Head Closure Studs Program is implemented through the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program, which monitors the condition of the closure studs and stud components and which is implemented and maintained in accordance with the general requirements for engineering programs.

The applicant states that the Reactor Head Closure Studs Program is consistent with GALL Section XI.M3, Reactor Head Closure Studs," and that implementation of the program provides reasonable assurance that the aging effects will be managed such that the components within the scope of license renewal will continue to perform their intended functions consistent with the CLB for the period of extended operation.

The applicant also states that, while RNP is not committed to the implementation of the regulatory guidance in RG 1.65, "Materials and Inspections for Reactor Vessel Closure Studs," October 1973, head closure stud fabrication details and preventive measures are consistent with the recommendations of the regulatory guide.

3.1.2.3.1.2 Staff Evaluation

The 10 program attributes in GALL AMP Section XI.M3, "Reactor Head Closure Studs," provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage loss of preload due to stress relaxation and loss of material due to wear in the RNP RV head closure studs. Although the applicant did not provide the program attribute descriptions for the Reactor Head Closure Studs Program in Section B.2.3 of Appendix B to the LRA, the applicant has stated that the program attributes for the Reactor Head Closure Studs Program are consistent with those specified in AMP XI.M3 of GALL. The applicant retains the program description of the Reactor Head Closure Studs Program, as well as the descriptions for the program's 10 attributes, on record at RNP. The staff has audited the Reactor Head Closure Studs Program for acceptability and has compared the program's 10 attributes to the 10 attributes described in GALL XI.M3. The audit of the Reactor Head Closure Studs Program, which is provided in the NRC audit report dated August 12, 2003, verified that the program attributes for the Reactor Head Closure Studs Program are acceptable when compared to the corresponding program attributes in GALL XI.M3. Based on these considerations, the staff concludes that the Reactor Head Closure Studs Program provides an acceptable means of managing loss of preload due to stress relaxation and loss of material due to wear in the RNP RV head closure studs.

3.1.2.3.1.3 UFSAR Supplement

In Section A.3.1.3 of Appendix A of the LRA, the applicant provides the UFSAR Supplement summary for the Reactor Head Closure Studs Program. The UFSAR Supplement description for the program states that the Reactor Head Closure Studs Program is credited for aging management of the reactor head closure studs and stud components for the aging effects/mechanisms of concern, including (1) loss of preload due to stress relaxation, and (2) loss of material due to wear. The UFSAR Supplement description states that the scope of the program includes aging management of the RV closure studs, nuts, and washers, and that inspections of these components are included within the scope of the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program.

Section B.2.3 of Appendix B of the LRA, "Reactor Head Closure Studs Program," states that the program attributes for the AMP are consistent with those recommended in GALL XI.M3, "Reactor Head Closure Studs." However, the staff's review of UFSAR Supplement Section A.3.1.3, on the Reactor Head Closure Studs Program, indicated that the UFSAR Supplement summary description for the Reactor Head Closure Studs Program did not reflect this. Therefore, in RAI B.1-1, the staff asked the applicant to clarify in the UFSAR Supplement summary descriptions for the RNP AMPS which of the AMPs are consistent with the corresponding AMPs described in GALL, Volume 2.

In its response to RAI B.1-1, dated April 28, 2003, the applicant stated that it would incorporate the following statement into the UFSAR Supplement summary descriptions for those RNP AMPs that are determined to be consistent with the program attributes of analogous programs in Section XI.M of GALL, Volume 2:

> This program is consistent with the corresponding program described in the GALL Report.
>
> Based on the applicant's response to RAI B.1-1, the staff concludes that the UFSAR Supplement for the Reactor Head Closure Studs Program is acceptable because it will reflect that the program attributes for the AMP are consistent with the corresponding program attributes recommended by the staff in GALL Program XI.M3, "Reactor Head Closure Studs."

3.1.2.3.1.4 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.2 Nickel-Alloy Nozzles and Penetrations Program

The applicant's -Alloy Nozzles and Penetrations program is discussed in LRA Section B.4.1 and is credited with managing the aging effects of SCC (including PWSCC) for selected components in the RV and internals at RNP.

3.1.2.3.2.1 Summary of Technical Information in the Application

The applicant stated that the -Alloy Nozzles and Penetrations Program is consistent with GALL XI.M11, Nickel-Alloy Nozzles and Penetrations." The applicant also proposed the following enhancements to the program that affect program elements in regard to the scope, acceptance criteria, and corrective actions:

- The RNP will maintain its involvement in industry initiatives (such as the Westinghouse Owners Group and the EPRI-MRP) during the period of extended operation.

- The RNP will perform evaluation of indications under the ASME Section XI Program.
- The RNP will perform corrective actions for augmented inspections using repair replacement procedures equivalent to those requirements in ASME Section XI.

3.1.2.3.2.2 Staff Evaluation

In LRA Section B.4.1, Nickel-Alloy Nozzles and Penetrations," the applicant described its AMP to manage aging effects of cracking due to stress corrosion, including primary water stress corrosion. The LRA stated that this AMP is consistent with GALL XI.M11, Nickel-Alloy Nozzles and Penetrations," with further enhancement. The GALL Report is based on industry Operating Experience (OE) through April 2001. The staff has reviewed recent industry OE for applicability. The applicant's program element, *Operating Experience*, as updated by the applicant's responses to NRC Bulletin 2001-01, Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," Bulletin 2002-01, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," and Bulletin 2002-2, Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," provides the applicant's review of VHP nozzle degradation events.

However, the staff has issued additional augmented inspection requirements for the VHP nozzles of U.S. PWR facilities since the time when the LRA for RNP was submitted by the applicant. These augmented inspection requirements are contained in NRC Order EA-03-009, which was issued on February 11, 2003, to all holders of operating licenses for PWR-designed light-water reactors. The applicant's description of the -Alloy Nozzles and Penetrations Program is therefore not reflective of the most recent CLB for resolving the issue of monitoring for PWSCC in the VHP nozzles at RNP. The staff evaluates the impact that NRC Order EA-03-009 will have on the program attributes for this AMP later in this section.

The applicant further stated that since this issue required resolution during the current licensing period, RNP would commit to continuing this resolution through the period of extended operation, and would participate in industry initiatives (Westinghouse Owners Group and the EPRI-MRP) to ensure that components are maintained within the CLB during the period of extended operation.

In Section B.4.1 of the LRA, Nickel-Alloy Nozzles and Penetrations," the applicant stated that it will commit to continuing the resolution of RV head penetration issues through the period of extended operation and will participate in industry initiatives (Westinghouse Owners Group and the EPRI Material Reliability Program) to ensure that the components are managed and maintained within the CLB during the period of extended operation. The staff issued RAI B.4.1-1 in order to ensure that the applicant's Nickel-Alloy Nozzles and Penetrations Program will be capable of monitoring, detecting, evaluating, and removing flaws in Class 1 nickel-based alloy components and welds, and to ensure the integrity of these components during the extended period of operation for RNP. In this RAI, the staff asked the applicant to confirm whether or not RNP is committed to implementing all NRC-approved inspection method activities, frequencies, and evaluation criteria that are recommended as a result of the industry's assessment initiatives on Inconel materials, as well as any further requirements that may result from the NRC staff's resolution of the industry's responses to NRC Bulletins 2002-01 and 2002-02, and/or resolution of the V.C. Summer issue. In RAI B.4.1-2, the staff asked the applicant to confirm if it is committed to compliance with the ASME Code, Section XI, IWB-4000 for repairs of components found to contain cracks, and IWB-7000 for replacement of components identified as susceptible to PWSCC.

The applicant provided the following generic response to RAIs B.4.1-1 and B.4.1-2, dated April 28, 2003:

> As stated in LRA Subsection A.3.1.28, Nickel-Alloy Nozzles and Penetrations Program, RNP commits to the following for the Nickel-Alloy Nozzles and Penetrations Program:
>
> 'Prior to the period of extended operation, the Nickel-Alloy Nozzles and Penetrations Program will incorporate the following: (1) CP&L will perform evaluation of indications under the ASME Section XI program, (2) CP&L will perform corrective actions for augmented inspections to repair and replacement procedures equivalent to those requirements in ASME Section XI, (3) CP&L will maintain its involvement in industry initiatives (such as the Westinghouse Owners Group and the EPRI Materials Reliability Project) during the period of extended operation.'

This commitment will be supplemented as follows:

> "(4) Prior to July 31, 2009, RNP will submit, for review and approval, the inspection plan for the Nickel-Alloy Nozzles and Penetrations Program, since ... implemented from the applicant's participation in industry initiatives."

This revision of the commitment has been reflected in the applicant's revised Commitment Item No. 31, as given in Attachment II to Serial Letter No. RNP-RA/03-0031, dated April 28, 2003. This commitment indicates that the applicant's inspection plan for the RNP Class 1 nickel-based alloy components and welds will be submitted for NRC review and approval prior to July 31, 2009.

On February 11, 2003, the staff issued NRC Order No. EA-03-009 to all holders of operating licenses for PWR-designed nuclear plants, including RNP. The order requires all PWR licensees to perform augmented inspections of their facility's Alloy 600 penetration nozzles and welds connecting the nozzles to the upper RV heads.[4] These augmented inspections include a combination of visual examinations and nonvisual NDE techniques that are required to be implemented at specific frequencies. The applicant submitted its 20-day response to NRC Order EA-03-009 by letter dated March 3, 2003.

The revision in Commitment No. 31 to submit the inspection plan for staff review and approval will permit the staff an opportunity to confirm that the applicant's inspection plan for RNP's VHP nozzles and their partial penetration J-groove welds will be in compliance with the augmented inspection requirements in NRC Order No. EA-03-009.[5] In addition, the applicant's commitment to submit the inspection plan for the Nickel-Alloy Nozzles and Penetrations Program to the NRC for review and approval will allow the staff to determine whether the applicant's proposed

[4]The staff's provisions and requirements in NRC Order No. EA-03-009 may be accessed at the following address on the World Wide Web:

http://www.nrc.gov/reactors/operating/ops-experience/vessel-head-degradation/vessel-head-degradation-files/order-rpv-inspections.pdf

[5]The scope of these statements include any relaxations or rescission of the requirements in NRC Order No. EA-03-009 that may be requested by the licensee and granted by the Director of the Office of Nuclear Reactor Regulation, or his designee.

inspections for other Class 1 nickel-based alloy components and weld locations will be done in accordance with the inspection methods recommended by the EPRI-MRP, as determined by the NRC to be reasonable for the design of the RNP facility and acceptable for implementation at the plant. This revised commitment in Commitment No. 31 therefore resolves RAI B.4.1-1.

The applicant's revision to Commitment No. 31 also indicates and confirms that the applicant will perform corrective actions for defects detected in Class 1 nickel-based alloy components and welds in accordance with the applicable repair and/or replacement provisions of Section XI to the ASME Boiler and Pressure Vessel Code. The revised commitment in Commitment No. 31 therefore resolves RAI B.4.1-2.

Based on the staff's review of the applicant's response to RAI B.4.1-1, the applicant's revision to Commitment No. 31 in Attachment II to CP&L Serial Letter RNP-RA/03-0031, and the new inspection requirements for the RNP VHP nozzles, the staff concludes that there is reasonable assurance that the Nickel-Alloy Nozzles and Penetrations Program will be capable of managing PWSCC-induced degradation of Class 1 nickel-based alloy components and welds in the RCPB for RNP. Based on this assessment, the staff concludes that the applicant's Nickel-Alloy Nozzles and Penetrations Program is consistent with the program attributes in GALL Program XI.M11, Nickel-Alloy Nozzles and Penetrations," and is acceptable.

3.1.2.3.2.3 UFSAR Supplement

The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program. The applicant 's UFSAR Supplement for the Nickel-Alloy Nozzles and Penetrations Program is documented in Section A.3.1.28 of Appendix A to the LRA and provides the following summary description for the program:

> The program includes (a) primary water stress corrosion cracking (PWSCC) susceptibility assessment to identify susceptible components, (b) monitoring and control of reactor coolant water chemistry to mitigate PWSCC, and (c) inservice inspection of reactor vessel head penetrations to monitor PWSCC and its effect on the intended function of the component. For susceptible penetrations and locations, the program includes an industry wide, integrated, long-term inspection program based on the industry responses to NRC Generic Letter (GL) 97-01.
>
> Prior to the period of extended operation, the Nickel-Alloy Nozzles and Penetrations Program will incorporate the following: (1) CP&L will perform evaluation of indications under the ASME Section XI program, (2) CP&L will perform corrective actions for augmented inspections to repair and replacement procedures equivalent to those requirements in ASME Section XI, (3) CP&L will maintain its involvement in industry initiatives (such as the Westinghouse Owners Group and the EPRI Materials Reliability Project) during the period of extended operation.

The first paragraph in the UFSAR Supplement summary description for the Nickel-Alloy Nozzles and Penetrations Program is not up-to-date and must be amended to reflect that the applicant's inspection program for the RNP VHP nozzles is based on the requirements in NRC Order No. EA-03-009 (February 11, 2003) and the applicant's response to the order dated March 3, 2003. The licensee should also confirm that the UFSAR Supplement summary description for the Nickel-Alloy Nozzles and Penetrations Program (as given is Section A.3.1.28 of Appendix A of the LRA) will be amended to reflect the augmented requirements in NRC Order No. EA-03-009 for the RNP RV head and its VHP nozzles. This is Confirmatory Item B.4.1-1.

The applicant provided its response to Confirmatory Item B.4.1-1 by letter dated September 16, 2003. In this response, the applicant confirmed that the scope of the Final Safey Analysis Report (FSAR) Supplement summary description for the Nickel-Alloy Nozzles and Penetrations Program will be amended to include the augmented requirements in NRC Order EA-03-009, as they apply to augmented inspections of the RNP reactor vessel head and VHP nozzles. Since the response confirms that the FSAR Supplement summary description for the AMP will be amended to reflect the applicability of the requirements in NRC Order EA-03-009, the staff concludes that the applicant's response to Confirmatory Item B.4.1-1 is acceptable and, Confirmatory Item B.4.1-1 is resolved.

In its response to RAI B.1-1, dated April 28, 2003, the applicant stated it would incorporate the following statement into the UFSAR Supplement summary descriptions for those RNP AMPs that are determined to be consistent with the program attributes of analogous programs in Section XI.M in GALL, Volume 2:

> This program is consistent with the corresponding program described in the GALL Report.

The applicant also stated that the UFSAR Supplement summary statement for those AMPs which take exception to one or more provisions (program attributes) of the corresponding program in GALL, Volume 2, will not incorporate this statement. The applicant's response to RAI B.1-1 indicates that the UFSAR Supplement summary description for the Nickel-Alloy Nozzles and Penetrations Program, as given in Section A.3.1.28 of Appendix A of the LRA, will be amended to reflect that the program attributes for the AMP are consistent with those recommended in GALL XI.M11, Nickel-Alloy Nozzles and Penetrations." The staff concludes that the UFSAR Supplement for the Nickel-Alloy Nozzles and Penetrations Program is acceptable because it will reflect that the program attributes for the AMP are consistent with the corresponding program attributes recommended by the staff in GALL XI.M11, Nickel-Alloy Nozzles and Penetrations." On the basis of this review, the staff concludes that the UFSAR Supplement summary description for the Nickel-Alloy Nozzles and Penetrations Program is in compliance with the requirements of 10 CFR 54.21(d).

3.1.2.3.2.4 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.3 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program

The applicant discusses its Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (henceforth identified as the CASS Program) in Section B.4.2 of Appendix B of the LRA. The applicant states that the scope of the CASS Program bounds aging management of CASS components within Class 1 boundaries of the RCS and connected systems at RNP, and that the program is credited for managing loss of fracture toughness due to thermal embrittlement of the CASS materials.

3.1.2.3.3.1 Summary of Technical Information in the Application

The applicant states that the CASS Program is consistent with GALL XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)," and that implementation of the program provides reasonable assurance that the aging effects will be managed such that the components within the scope of license renewal will continue to perform their intended functions consistent with the CLB for the period of extended operation.

3.1.2.3.3.2 Staff Evaluation

The 10 program attributes in GALL XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel," provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage thermal aging and hence loss of fracture toughness properties in RCS components made from CASS.

The GALL program description in Section XI.M12 notes that the program is based on research data using laboratory-aged and service-aged materials, and concludes that the program as defined is sufficient to manage the effects of thermal aging embrittlement on the intended function of CASS components. Flaw tolerance evaluations are based on an extensive test program performed by the Argonne National Laboratory (ANL) assessing the extent of thermal aging of CASS materials. The ANL compiled an extensive database of compositions of CASS materials exposed to a temperature range of 550–750 °F for up to 58,000 hours, and used these data to estimate the extent of thermal aging in developing fracture toughness determination procedures. The results of this study have been reviewed and approved by the NRC, and incorporated into plant-specific analysis of RCS piping and RCP casings. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program and procedures are generally credited with implementation of the Thermal Aging Embrittlement Program.

The program attributes for GALL XI.M12 are in accordance with the staff's position on evaluation of CASS materials, as given in the staff's interim staff guidance on CASS, dated May 19, 2000.[6] Although the applicant did not provide the program attribute descriptions for the CASS Program in Section B.4.2 of Appendix B of the LRA, the applicant has stated that the program attributes for the CASS Program are consistent with those specified in AMP XI.M12 of GALL. The applicant retains the program description of the CASS Program as well as the descriptions for the program's 10 attributes on record at RNP. The staff will inspect the CASS Program for acceptability and compare the program's 10 attributes to the 10 attributes

[6]Letter from C.I. Grimes (NRC) to D.J. Walters (NEI), *License Renewal Issue No. 98-0030, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components,* Project No. 690, dated May 2000.

described in GALL XI.M12. Inspections of LR applicant scoping analyses, AMRs, and AMPs are a normal part of the agency's process for reviewing LRAs. The staff's inspection of the CASS Program will verify that the program attributes for the CASS Program are acceptable when compared to the corresponding program attributes in GALL XI.M12. Based on these considerations, the staff concludes that the CASS Program provides an acceptable means of managing loss of fracture toughness induced by thermal aging in RCS components made from CASS.

3.1.2.3.3.3 UFSAR Supplement

The applicant provides its UFSAR Supplement summary for the CASS Program in Section A.3.1.29 of Appendix A of the LRA. In the UFSAR Supplement summary for the CASS Program, the applicant states that the CASS Program is credited for aging management of CASS components within Class 1 boundaries of the RCS and connected systems at RNP and that the aging effect/mechanism of concern is loss of fracture toughness due to thermal embrittlement of CASS. The applicant also states that the flaw tolerance evaluations for RCP casings and primary loop CASS components have been done in accordance with a fracture toughness methodology that has been approved by the NRC, and that, consistent with NRC guidance, the RNP program does not include additional inspections of pump casings, valve bodies, or piping.

In RAI B.4.2-1, the staff informed the applicant that its UFSAR Supplement summary for the CASS Program states that the flaw tolerance evaluations for RCP casings and primary loop CASS components have been done in accordance with a fracture toughness methodology that has been approved by the NRC, and that, consistent with NRC guidance, the RNP program does not include additional inspections of pump casings, valve bodies, or piping. Therefore, the staff asked the applicant to clarify which fracture toughness methodology and NRC guidance it was referring to in its UFSAR Supplement summary for the CASS Program, and to provide basis for how its program was consistent with the NRC guidance. The staff also asked the applicant to clarify which type of inspections will be performed on CASS pump casings, valve bodies, and piping to ensure that cracking of Class 1 CASS components will be detected prior to crack growth beyond the critical crack size for components, as assessed for thermal aging in the component materials.

The applicant submitted its response to RAI B.4.2-1 by letter dated April 28, 2003. The applicant's response to the RAI, in part, makes the following clarification with respect to the guidelines referenced in Section A.3.1.29 of Appendix A of the LRA.

> The NRC guidance referenced in LRA Subsection A.3.1.29 is from the GALL Report regarding additional inspections of pump casings, valve bodies, and piping. The guidance is discussed in the Detection of Aging Effects section of program XI.M.12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)."
>
> Inspection of valves, piping/fittings, and pump casings, performed under the Section XI Program, in accordance with IWB-2400 or IWC-2400, provides timely detection of cracks. Consistent with NRC guidance, the RNP program does not include additional inspections of pump casings, valve bodies, or piping. An evaluation has been performed demonstrating the applicability of Code Case N-481 (which incorporates surface exams) to RCP casings over the period of extended operation. Also a flaw tolerance evaluation has been performed for RCS loop piping during the period of extended operation, which includes consideration of fracture toughness and thermal aging of CASS components.

The evaluation demonstrates margin between detectable flaw size and flaw instability. Accordingly, an inspection program to manage this effect for primary loop piping/fittings is not warranted.

The applicant's response to RAI B.4.2-1 clarifies that the guidelines referred to in the UFSAR Supplement summary description for the CASS Program are those documented in the *Detection of Aging Effects* program attribute of GALL XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)." The applicant did not clarify which evaluations contained the flaw tolerance evaluations for the RCS loop piping (i.e., the leak-before-break (LBB) analysis for the RCS loop piping) and RCP pump casings. However, the UFSAR Supplement summary descriptions on the TLAA for LBB and the TLAA for the RCP casings do indicate the flaw tolerance evaluations in support of the TLAAs on the RCS loop piping and RCP casings are given in WCAP-15628 and WCAP-15636, Revision 1, respectively. The applicant's information in RAI B.4.2-1, when taken in context with the information in Sections A.3.2.5.1 and A.3.2.5.2 of Appendix A of the LRA, clarifies which guidance and flaw tolerance evaluations are referred to in UFSAR Supplement summary description for the CASS Program (i.e., Section A.3.1.29 of the LRA).

The evaluation referred to by the applicant in its response to RAI B.4.2-1 is the flaw tolerance evaluation in the LBB assessment for RNP, as given in WCAP-15628. The TLAA for the LBB analysis on the RCS loop piping (as given in Section A.3.2.5.1 of Appendix A of the LRA) and the TLAA for supporting the alternative Code Case N-481 inspection requirements for the RCP casings (as given in Section A.3.2.5.2 of Appendix A of the LRA) are related to this AMP. The staff evaluates these TLAAs in Sections 4.6.1.1 and 4.6.1.2 of this SER.

The applicant's response to RAI B.4.2-1 indicates that the LBB flaw tolerance evaluation for the RCS loop piping (which is given in WCAP-15628) does not warrant an inspection program for the RCS loop piping. However, LBB analyses approved by the staff for primary loop piping in PWR facilities are implemented to support the conclusion that leaks from postulated flaws in the piping will be detected prior to any catastrophic full guillotine failure of the piping and that, therefore, pipe-whip restraints used to protect nearby safety-related components against pipe whip are no longer needed to meet the requirements of NRC General Design Criterion 4. These LBB analyses are required to be submitted to the staff for review and approval.

However, LBB analyses do not, per se, relieve licensees from performing the ISI examinations required by Table IWB-2500-1 to Section XI of the ASME Boiler and Pressure Vessel Code for primary coolant loop piping, valves, or pump casings, unless regulatory relief is granted by the NRC under applicable provisions in 10 CFR 50.55a from meeting the staff's ISI requirements of 10 CFR 50.55a(g)(4). The staff seeks confirmation that, although an LBB flaw tolerance evaluation has been performed for the extended period of operation for RNP (as given in WCAP-15628), the applicant will continue to perform those ISI examinations for the primary coolant loop piping, valves, and pump casings that are required by Table IWB-2500-1 of Section XI to the ASME Boiler and Pressure Vessel Code, unless relief has been granted by the NRC under applicable provisions in 10 CFR 50.55a from meeting the staff's ISI requirements of 10 CFR 50.55a(g)(4). If relief has been granted from any of the required ISI examinations for the primary coolant loop piping, valves, or pump casings, the staff seeks confirmation of the applicable NRC staff safety evaluation granting this relief and the specific ISI examination requirements for which relief has been granted. The staff also seeks confirmation that the UFSAR Supplement summary description will be amended to reflect the information in the applicant's response to this Confirmatory Item. This is Confirmatory Item B.4.2-1.

In its response to Confirmatory Item B.4.2-1, dated August 14, 2003, the applicant confirmed that the UFSAR Supplement summary description for the CASS Program will be amended to indicate that the applicant will continue to perform the inservice inspections of the ASME Class 1 primary loop piping, valve bodies, and pump casings, as required by 10 CFR 50.55a and Section XI of the ASME Boiler and Pressure Vessel Code, unless relief has been requested and granted by the NRC under applicable provisions in 10 CFR 50.55a. The applicant also confirmed that the summary description for the CASS program will also be amended to indicate that the NRC did approve some specific relief requests (i.e., in the NRC safety evaluation report dated September 26, 2002) on some of the specific ISI requirements for the ASME Class 1 primary loop piping, valve bodies, and pump casings for the fourth 10-year ISI interval for RNP.

The staff reviewed the information in the safety evaluation report of September 26, 2002, and confirmed that the reliefs granted would not impact the acceptability of the program attributes for the CASS Program. Since the applicant's response to Confirmatory Item B.4.2-1 indicates that the UFSAR Supplement summary description will be modified to demonstrate continued compliance with the requirements of 10 CFR 50.55a and Section XI of the ASME Boiler and Pressure Vessel Code, the staff concludes that the UFSAR Supplement summary description for the CASS Program is acceptable. Confirmatory Item B.4.2-1 is resolved.

In its response to RAI B.1-1, dated April 28, 2003, the applicant also stated it would incorporate the following statement into the UFSAR Supplement summary descriptions for those RNP AMPs that are determined to be consistent with the program attributes of analogous programs in Section XI.M in GALL, Volume 2:

> This program is consistent with the corresponding program described in the GALL Report.

The applicant also stated that the UFSAR Supplement summary statement for those AMPs which take exception to one or more provisions (program attributes) of the corresponding program in GALL, Volume 2, will not incorporate this statement. The applicant's response to RAI B.1-1 indicates that the UFSAR Supplement summary description for the CASS Program, as given in Section A.3.1.29 of Appendix A of the LRA, will be amended to reflect that the program attributes for the AMP are consistent with those recommended in GALL XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel." The staff concludes that the UFSAR Supplement for the CASS Program is acceptable because it will reflect that the program attributes for the AMP are consistent with the corresponding program attributes recommended by the staff in GALL XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel," and with the ISI requirements of 10 CFR 50.55a.

3.1.2.3.3.4 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.4 PWR Vessel Internals Program

The applicant discusses the PWR Vessel Internals Program in Section B.4.3 of the LRA, and credits this program with the management of various aging effects that may be applicable to the components that are located internal to the RV.

3.1.2.3.4.1 Summary of Technical Information in the Application

In Section B.4.3 of Appendix B of the LRA, the applicant states that the PWR Vessel Internals Program is credited for managing the following aging effects in the RNP RV internals:

- cracking due to stress corrosion cracking
- cracking due to irradiation-assisted stress corrosion cracking
- change in dimensions due to void swelling
- loss of preload due to irradiation creep
- loss of preload due to stress relaxation
- reduction of fracture toughness due to thermal embrittlement
- reduction of fracture toughness due to neutron irradiation embrittlement

The applicant states that the PWR Vessel Internals Program will incorporate the following enhancements.

- To address change in dimensions due to void swelling, RNP will continue to participate in industry programs to investigate this aging effect and determine the appropriate AMP.

- To address baffle and former assembly issues, RNP will continue to participate in industry programs and will implement appropriate program enhancements to manage the aging effects associated with the baffle and former assembly.

- As Westinghouse Owner's Group and EPRI Materials Reliability Project research projects are completed, RNP will evaluate the results and factor them into the PWR Vessel Internals Program. The expected results include identification of components which are the most limiting and most susceptible and identification of appropriate inspection techniques.

- RNP will implement an augmented inspection during the license renewal term. Augmented inspections, based on required program enhancements, will become part of the ASME Section XI Program. Corrective actions for augmented inspections will be developed using repair and replacement procedures equivalent to those requirements in

ASME Section XI.

The applicant states that the PWR Vessel Internals Program is consistent with GALL Section XI.M16, PWR Vessel Internals, with the following exceptions:

- Preventive Actions—The PWR Vessel Internals Program relies on the Water Chemistry Program for maintaining high water purity to reduce susceptibility to cracking due to SCC. The Water Chemistry Program was evaluated and was found to be consistent with GALL with exceptions that have no adverse effects on the ability of the program to manage aging effects. As stated in the description of the Water Chemistry Program, the differences from the GALL chemistry program were evaluated and determined not to be exceptions.

- Parameters Monitored/Inspected and Detection of Aging Effects—Augmented inspections will be performed based on the results of RNP's participation in industry research. The GALL report recommends that the program monitor the effects of cracking on the intended function of the component by detection and sizing of cracks by augmentation of ISI, in accordance with the requirements of the ASME Code, Section XI, Table IWB 2500-1. The determination of consistency cannot be made at this time so this element is considered inconsistent.

3.1.2.3.4.2 Staff Evaluation

The staff's corresponding program and program attributes for the PWR Vessel Internals Program are given in GALL XI.M16, PWR Vessel Internals." The applicant states that the PWR Vessel Internals Program is consistent with GALL XI.M16 with the exception of the two inconsistencies identified in Section 3.1.2.3.8.1 of this SER. The first of these involves an inconsistency regarding implementation of another AMP, the Water Chemistry Program, as it relates to control of the impurity levels in the RCS and mitigating cracking in the RV internal components at RNP. In the *Preventive Actions* program attribute of GALL XI.M16, the staff identifies the following:

> The requirements of ASME Section XI, Subsection IWB, provide guidance on detection, but do not provide guidance on methods to mitigate cracking. Maintaining high water purity reduces susceptibility to cracking due to SCC. Reactor coolant water chemistry is monitored and maintained in accordance with the EPRI guidelines in TR-105714. The program description and evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Chapter XI.M2, "Water Chemistry."

This enhancement to use the Water Chemistry Program as a preventive/mitigative-based AMP for mitigating corrosive-induced aging mechanisms in Class 1 components is consistent with the position in GALL XI.M2 that water chemistry programs for the primary coolant be implemented in accordance with the water chemistry guidelines of EPRI Topical Report 105714. The staff therefore concludes that this inconsistency with GALL is acceptable.

The applicant also stated that it had an inconsistency with the *Parameters Monitored/Inspected* and *Detection of Aging Effects* program attributes of GALL Program XI.M16, PWR Vessel Internals." The applicant stated that augmented inspections will be performed based on the results of RNP's participation in industry research on RV internals degradation, but clarified that since these industry efforts were currently in progress, the determination of consistency could not be made at this time. The staff's evaluation of this inconsistency with GALL XI.M16 is discussed in the remainder of this section (SER Section 3.1.2.4.8.2)

The applicant did not indicate whether the PWR Vessel Internals Program, as it currently exists, will monitor for the following aging effects in the RNP RV internal components (1) loss of material due to wear or erosion, (2) cracking due to thermal fatigue, SCC or IASCC, (3) loss of preload due to stress relaxation in RV internal bolted or fastened connections, (4) loss of fracture toughness due to neutron irradiation embrittlement or to thermal aging for CASS, martensitic SS, or precipitation hardened SSs and (5) dimensional changes due to void swelling. Instead, the applicant indicated that it is relying on its participation in MRP and Westinghouse industry initiatives as its bases for determining which aging effects are applicable for the RNP RV internal components and for determining the type of inspections that need to be performed.

In RAI B.4.3-1, staff asked the applicant to provide additional specific details on how the RNP PWR Internals Program will manage the following effects in the RNP RV internal components.

- void swelling
- loss of material, loss of preload, and cracking in RV internal bolted or fastened connections, including baffle/former bolts
- loss of material and loss of preload in components such as holddown springs and clevis inserts, as applicable
- cracking in RV internals made from austenitic alloys (Inconel alloys and/or austenitic SS alloys) and loss of fracture toughness in RV internals made from CASS or in RV internals made from austenitic alloys with neutron fluences projected to be above $5x10^{20}$ n/cm^2

In the RAI, the staff asked the applicant to include a clarification of the type of inspection methods that will be used to monitor for the aging effects, identification of the frequency for the inspections, identification of the components the inspections will be performed on, a discussion of the methods that will be used to qualify a given inspection method to detect the aging effect in question, and identification of the acceptance criteria that will be used to initiate corrective actions if degradation is detected in the RV internal components. The staff informed the applicant that, if industry participation is to be used as a basis for determining whether inspections are necessary for monitoring of these aging effects, a commitment is requested from CP&L to implement the inspection methods, inspection frequencies, inspection qualification techniques, and acceptance criteria for these aging effects as recommended by Westinghouse, applicable MRP ITGs, or other relevant industry organizations for management of these aging effects.

In the RAI, the staff also informed the applicant that, for the inspection of RV internal baffle bolts, the staff's recommended position in GALL XI.M16, PWR Vessel Internals Program," is that VT-3 examinations have not been capable of identifying cracks at the junctures of the baffle bolt heads and shanks, and that the GALL therefore recommends that more stringent augmented inspection techniques, such as enhanced VT-1 visual methods or ultrasonic examination techniques be used to inspect the shanks of the baffle bolts below the bolt heads and the regions of the bolt head-shank junctures. The staff asked for a clarification of why the inspection techniques selected for the RV internal baffle bolts were considered to be capable of detecting cracking in these regions. As a minimum, the staff requested that CP&L either commit to performing a one-time enhanced VT-1 or UT inspection of the baffle bolt shanks and bolt head-shank junctures, or else provide an additional clarification of how the commitment to implement the recommended inspection methods and frequencies from industry initiatives on PWR vessel internal baffle bolts will ensure that cracking in the shanks and the bolt head-shank junctures will be detected.

By letter dated April 28, 2003, the applicant provided the following response to RAI B.4.3-1:

> Industry consensus on acceptable inspection techniques for reactor vessel internals aging mechanisms has not been reached. Previous applicants have committed to participating in industry activities to characterize the aging mechanisms and determine appropriate inspection techniques. In Subsection A.3.1.30, PWR Vessel Internals Program, of the LRA, RNP commits to the following for the PWR Vessel Internals Program:
>
> "This is a new program that will incorporate the following commitments (1) To address change in dimensions due to void swelling, RNP will continue to participate in industry programs to investigate this aging effect and determine the appropriate AMP, (2) To address baffle and former assembly issues, RNP will continue to participate in industry programs and will implement appropriate program enhancements to manage the aging effects associated with the Baffle and Former Assembly, (3) As WOG and EPRI Materials Reliability Project (MRP) research projects are completed, RNP will evaluate the results and factor them into the PWR Vessel Internals Program. The expected results include identification of components which are the most limiting and most susceptible and identification of appropriate inspection techniques, (4) RNP will implement an augmented inspection during the license renewal term. Augmented inspections, based on required program enhancements, will become part of the ASME Section XI program. Corrective actions for augmented inspections will be developed using repair and replacement procedures equivalent to those requirements in ASME Section XI."
>
> In the RNP response to RAI B.4.3-2, RNP has supplemented this commitment as follows:
>
> RNP will submit, for NRC review and approval, the inspection plan for the PWR Vessel Internals Program, as it will be implemented based on participation in industry initiatives, 24 months prior to the augmented inspection.

The applicant's response to RAI B.4.3-1 indicates that the applicant is relying on its participation in industry initiatives on management of aging in PWR vessel internals (including those that may be initiated by the WOG or the EPRI-MRP) as its basis to developing its inspection plan for the RV internal components at RNP. The applicant's basis for developing the inspection attributes for the PWR Vessel Internals Program is not entirely consistent with the established program attributes of GALL XI.M16, PWR Vessel Internals," because the applicant is relying entirely on the results and recommendations of industry initiatives on PWR RV internals as the basis for developing the inspection plan for the RNP RV internal components. However, this basis (and deviation from the GALL program) is not inconsistent with the staff's recommended approach taken in discussion sections of certain relevant AMRs in the commodity group items of Chapter IV.B2 of GALL, Volume 2 (e.g., the AMRs in commodity group items for RV internal components that may be susceptible to void swelling or those for evaluating aging effects in baffle bolt components).

The commitments discussed in the applicant's response to RAI 4.3-1 and earlier in this section ensure that the applicant's inspection plan for the RNP RV internals will be submitted for staff review and approval 24 months prior to implementation. The allotted time for submittal of the inspection plan will provide the staff with opportunity to resolve any differences between the staff and the applicant regarding the scope, inspection method techniques and qualifications, frequencies, and acceptance criteria for the RV internal inspections proposed in the inspection plan. The applicant's commitments for the PWR Vessel Internal Program are available to the public in Commitment Item No. 33 of Attachment II to CP&L Serial Letter No. RNP-RA/03-0031, dated April 28, 2003.

Based on these considerations and the commitments given in Commitment Item No. 33 of Attachment II to CP&L Serial Letter No. RNP-RA/03-0031, the staff concludes that the PWR Vessel Internals Program provides an acceptable means of managing any aging effects that may be applicable to RNP RV internal components, and the second inconsistency with GALL AMP XI.M16 and RAI B.4.3-1 is resolved.

3.1.2.3.4.3 UFSAR Supplement

The applicant provides the following UFSAR Supplement summary description for the PWR Vessel Internals in Section A.3.1.30 of Appendix A of the LRA.

> The PWR Vessel Internals Program includes (a) participation in industry programs and initiatives to determine appropriate inspection techniques for use in managing aging effects, and (b) monitoring and control of reactor coolant water chemistry in accordance with the Water Chemistry Program to ensure the long-term integrity and safe operation of pressurized water reactor vessel internal components. This is a new program that will incorporate the following commitments: (1) to address change in dimensions due to void swelling, RNP will continue to participate in industry programs to investigate this aging effect and determine the appropriate AMP, (2) to address baffle and former assembly issues, RNP will continue to participate in industry programs and will implement appropriate program enhancements to manage the aging effects associated with the Baffle and Former Assembly, (3) as WOG and EPRI Materials Reliability Project (MRP) research projects are completed, RNP will evaluate the results and factor them into the PWR Vessel Internals Program. The expected results include identification of components which are the most limiting and most susceptible and identification of appropriate inspection techniques, (4) RNP will implement an augmented inspection during the license renewal term. Augmented inspections, based on required program enhancements, will become part of the ASME Section XI program. Corrective actions for augmented inspections will be developed using repair and replacement procedures equivalent to those requirements in ASME Section XI.

In RAI B.4.3-2, the staff informed the applicant that it seeks a commitment from the applicant that prior to the period of extended operation, the applicant will submit for review and approval its inspection plan for the PWR Vessel Internals Program that will result from the applicant's participation of industry initiatives on PWR RV internal components and a commitment to implement the recommended inspection activities, frequencies, and acceptance criteria that will result from these initiatives. In the RAI, the staff asked the applicant to amend its UFSAR Supplement summary description for the PWR Vessel Internals Program to incorporate this commitment, including specification of the date by which the inspection plan will be submitted by. In addition, the staff requested amendment of the UFSAR Supplement summary description for the PWR Vessel Internals Program to reflect the information provided in its responses to RAI B.4.3-1.

In its response to RAI B.4.3-2, dated April 28, 2003, the applicant stated that it would revise its UFSAR Supplement summary description for the PWR Vessel Internals Program, as given in

Section A.3.1.30 of Appendix A to the LRA, to incorporate the supplemental commitments discussed in the applicant's response RAI B.4.3-1. This includes the revision of the UFSAR Supplement summary description to include the commitment to submit the inspection plan for the PWR Vessel Internals Program 24 months prior to implementation before the period of extended operation. This is consistent with the staff's basis and analysis for accepting the AMP, as given in Section 3.1.2.3.4.2. The staff confirmed that the applicant's revised LRA Commitment No. 33 to Attachment II to CP&L Serial Letter No. RNP-RA/03-0031, dated April 28, 2003, incorporates this commitment. The staff will confirm that the applicant has incorporated the commitment regarding the PWR Vessel Internals Program into the UFSAR Supplement summary description of Section A.3.1.30 of Appendix A of the LRA when the applicant revises its UFSAR Supplement for this AMP. This was Confirmatory Item B.4.3-1.

In its response to Confirmatory Item B.4.3-1, dated December 10, 2003, the applicant stated that it provided an updated version of Commitment No. 33 in RNP Serial Letter RNP-RA/03-0031, dated April 28, 2003, which included a commitment to submit the inspection plan for the PWR Vessel Internal Program for NRC review and approval. In the response to Confirmatory Item B.4.3-1, the applicant also confirmed that it would amend to UFSAR Supplement summary description for the PWR Vessel Internals Program, as given in Section A.3.1.30 of Appendix A to the LRA, to incorporate a statement that reflects that the PWR Vessel Internal Program will be submitted to the staff for review and approval 24 months prior to implementation. Since the applicant's response reflects the commitment in Commitment No. 33 for submittal of the AMP for staff review and approval, the staff concludes that the applicant's response to Confirmatory Item B.4.3-1 is acceptable and Confirmatory Item B.4.3-1 is resolved. Based on this assesment and the resolution Confirmatory Item B.4.3-1, the staff concludes the UFSAR Supplement summary description for the PWR Vessel Internals Program is acceptable.

3.1.2.3.4.4 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.5 Steam Generator Tube Integrity Program

The applicant discusses its Steam Generator Tube Integrity Program in LRA Section B.2.4, Steam Generator Tube Integrity Program." The applicant credits this AMP with managing cracking and loss of material in the SG tube bundle, tube plugs, tube support plates, and antivibration bars in the RNP Sgs.

3.1.2.3.5.1 Summary of Technical Information in the Application

The applicant stated that the AMP is consistent with GALL XI.M19, Steam Generator Tube Integrity." The applicant also stated that NRC GL 97-05, Steam Generator Tube Inspection Guidelines," requires PWR licensees to verify that SG tube inspection practices are consistent with existing regulatory requirements and plant licensing bases. In response to GL 97-05, the applicant has committed to implement the guidance of NEI 97-06, Steam Generator Program Guidelines," with exceptions, as described in the RNP correspondence dated March 16, 1998. In a letter to the applicant dated August 13, 1998, the NRC concluded after reviewing the applicant's response to GL 97-05 that the applicant had complied with the RNP licensing basis for the SG tube inspection techniques.

The applicant states that the RNP Steam Generator Tube Integrity Program is continually upgraded based on industry experience and research via the operating experience and self-assessment programs. Continual improvement of the AMP has provided an effective means of ensuring the integrity of the SG tubes. The applicant stated that the overall effectiveness of the Steam Generator Tube Integrity Program is supported by the operating experience for SSCs which are influenced by the RNP Steam Generator Tube Integrity Program. No tube integrity related degradation has resulted in loss of component intended function.

The applicant concludes that the Steam Generator Tube Integrity Program is consistent with GALL XI.M19, and that the continued implementation of the program provides reasonable assurance that the aging effects will be managed such that the components within the scope of the program will continue to perform their intended functions consistent with the CLB for the period of extended operation.

3.1.2.3.5.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.2.4 to ensure that the aging effects caused by corrosion will be adequately managed so that the intended functions of the SG tubes will be maintained consistent with the CLB throughout the period of extended operation. The staff confirmed the applicant's claim of consistency during the AMP audit. In addition, the staff determined whether the applicant properly applied the GALL program to its facility.

The 10 program attributes in GALL XI.M19 provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage aging effects due to corrosion. Although the applicant did not provide the program attribute descriptions in LRA Section B.2.4, the applicant has stated that the program attributes are consistent with those specified in GALL XI.M19. The applicant retains the program description on record at RNP.

The staff has inspected the RNP program on site for acceptability and compared the program's 10 attributes to the attributes described in GALL XI.M19. Inspections of LRA scoping analyses, AMRs, and AMPs are a normal part of the NRC's process for reviewing LRAs. Furthermore, the staff has reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program. In letters dated April 28 and June 13, 2003, the applicant responded to the staff's RAI. The staff's RAI and the applicant's responses are discussed as follows.

In LRA Section B.2.4, the applicant stated that its Steam Generator Tube Integrity Program is performed under the overall Steam Generator Program at RNP. In RAI B.2.4-1, the staff asked the applicant to discuss the overall" steam generator program and in particular, the Steam Generator Tube Integrity Program. In its response to RAI B.2.4-1, the applicant stated that the Steam Generator Program, PLP-114, is an RNP-specific program incorporating the guidance of NEI 97-06, Steam Generator Program Guidelines." The overall Steam Generator Program envelops the Steam Generator Tube Integrity Program. The staff finds the applicant's response to RAI B.2.4-1 acceptable because the applicant has clarified that its Steam Generator Tube Integrity Program is a part of the overall steam generator program and has incorporated the industry guidance document, NEI 97-06.

In LRA Section B.2.4, the applicant presented a table of relevant SG components with associated aging effects and aging mechanisms. In RAI B.2.4-2, the staff asked the applicant to (a) clarify whether the aging effects and mechanisms listed in the table are taken from actual degradation observed at RNP, potential degradation, or generic degradation, (b) discuss the current and past degradation in the RNP replacement SG, (c) discuss how the degraded SG components have been and will be dispositioned, and (d) discuss the type and vendor of tube plugs.

In its response to RAI B.2.4-2, the applicant stated that the aging mechanisms listed in Section LRA B.2.4 are representative of potential aging effects/mechanisms. There has been no indication of corrosion-related degradation in the RNP SG tubes to date. There has been a total of 19 SG tubes plugged through November 2002. Four of these were preventively plugged due to probe restriction. The applicant stated that the tubes were plugged due to their inability to pass a qualified probe. No active degradation was detected prior to plugging. Five tubes were plugged due to loose part indications. The remaining 10 tubes were plugged due to wear indications. The Corrective Action Program addresses degraded SG components. With regard to tube plugs, one plug consists of a Westinghouse Alloy 600 mechanical plug with Alloy 690 plug-in-plug. The remaining plugs are CE Alloy 690 mechanical roll plugs.

The staff finds the applicant's response to RAI B.2.4-2 acceptable because the applicant has clarified the aging effects and degradation mechanisms of SG components. The applicant's action with regard to degraded tubes is consistent with GALL XI.M19.

By letter dated March 16, 1998, the applicant responded to NRC GL 97-05, Steam Generator Tube Inspection Guidelines." In the letter, the applicant stated that it is committed to implement the guidance of NEI 97-06, with exceptions. In RAI B.2.4-3, the staff asked the applicant to (a) clarify whether it will follow NEI 97-06 during the extended period of operation because the applicant's commitment to NEI 97-06, which it made in the March 16, 1998, letter, was part of its response to GL 97-05 only and was not made in the spirit or regulatory framework of the LRA (B) discuss whether the Steam Generator Tube Integrity Program will follow the NEI 97-06 version published at the time of the extended period of operation, and (C) discuss whether it will take any exception(s) to NEI 97-06.

In its response to RAI B.2.4-3, the applicant stated that RNP is currently utilizing the guidance of Revision 1 of NEI 97-06. RNP will continue to evaluate and implement new guidance provided by future revisions of NEI 97-06. RNP will evaluate the details of new revisions to NEI 97-06 as they are released to determine if exceptions are needed. The process of evaluating changes to the Steam Generator Tube Inspection Program will continue during the period of extended operation. As a result of the above, the following statement will be added to LRA, UFSAR Supplement, Appendix A, Subsection A.3.1.4, Steam Generator Tube Integrity Program: As part of the existing program, RNP will evaluate the details of new revisions to NEI 97-06 as they are released to determine if exceptions are needed. The process of evaluating changes to the Steam Generator Tube Integrity Program will continue during the period of extended operation.

The staff finds the applicant's response to RAI B.2.4-3 acceptable because the applicant has committed to follow NEI 97-06, which is consistent with GALL XI.M19. However, the staff has the following generic observation regarding NEI 97-06.

All PWR licensees have committed voluntarily to a SG degradation management program described in NEI 97-06, Steam Generator Program Guidelines." The GALL Report recommends that an AMP based on the recommendations of NEI 97-06 guidelines, or some other alternate regulatory basis for SG degradation management, should be developed to ensure that this aging effect is adequately managed.

At present, the NRC staff does not plan to endorse NEI 97-06 or detailed industry guidelines referenced therein. The staff is working with the industry to revise plant technical specifications to incorporate the essential elements of the industry's NEI 97-06 initiative as necessary to ensure tube integrity is maintained. This would require implementation of programs to ensure that performance criteria for tube structural and leakage integrity are maintained, consistent with the plant design and licensing basis. NEI 97-06 provides guidance on programmatic details for accomplishing this objective. These guidelines apply to all degradation or damage mechanisms. However, these programmatic details would be outside the scope of the technical specifications.

As part of the NRC's Reactor Oversight Program, the NRC would monitor the effectiveness of these programs in terms of whether the bottom line goals of these programs are being met, particularly whether the tube structural and leakage integrity performance criteria are in fact being maintained. The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects for the period of extended operation.

In the March 16, 1998, letter, the applicant discussed two exceptions to NEI 97-06. Exception Number 2 is related to NEI 97-06, Section 2.2, Accident-Induced Leakage Performance Criterion." In the letter, the applicant stated that the RNP UFSAR does not calculate radiological doses to the control room; therefore, the NEI 97-06 leakage performance criterion will only be applied to radiological dose calculations contained in applicable analyses in the UFSAR. The staff is not clear whether the applicant will take the same exception under the LRA. In RAI B.2.4-4, the staff asked the applicant to (1) identify the applicable analyses in the UFSAR that were referenced, (2) explain, in terms of NEI 97-06 specifications or licensing design basis, why it is acceptable that radiological doses to the control room are not calculated, and (3) describe the condition monitoring assessment and operational assessment that will be performed during the extended period of operation in terms of leakage calculations.

In its response to RAI B.2.4-4, the applicant stated that SG tube leakage is an input to the main steam line break analysis, which is described in UFSAR Section 15.1.5. Radiological doses to control room operators as a result of an accident are described in UFSAR Section 15.6.5.5.4.

Additionally, the applicant has requested technical specification changes and a revised radiological source term in accordance with 10 CFR 50.67. Condition monitoring and operational assessments are performed in accordance with EPRI TR-107621, Steam Generator Integrity Assessment Guideline." The applicant performs an assessment of tube integrity after each SG inspection. Primary-to-secondary leakage is limited by the leakage requirement in Technical Specification 3.4.13.

The staff finds the applicant's response to RAI B.2.4-4 acceptable because the applicant's tube integrity assessment follows EPRI guidelines and its leakage calculations follow the CLB.

In Section LRA B.2.4, the applicant stated that, "the RNP steam generator tube integrity program is continually upgraded based on industry experience and research via the Operating Experience and Self-Assessment Programs." In RAI B.2.4-5, the staff asked the applicant to (1) describe in detail how the Steam Generator Tube Integrity Program is upgraded via the Operating Experience and Self-Assessment Programs, and (2) describe in detail the Operating Experience and Self-Assessment Programs.

In its response to RAI B.2.4-5, the applicant stated that the Operating Experience Program and the Self-Assessment Program contribute to the upgrade of the Steam Generator Tube Integrity Program by identifying and recommending program improvements. The Operating Experience and Self-Assessment Programs were described in Attachment D of the RNP submittal entitled, Response to Request for Additional Information Pursuant to 10 CFR 50.54(f) Regarding Adequacy and Availability of Design Bases Information," dated February 11, 1997. In that submittal, the applicant stated that the Operating Experience Program provides the process for assessing operating experiences from industry sources for possible impact on the operation of CP&L nuclear plants, as well as providing the mechanism for sharing operating experience information among CP&L's nuclear sites. Where action is required, corrective actions are initiated to eliminate or reduce the probability of similar incidents. The program also disseminates appropriate information of importance to affected groups.

The Operating Experience Program includes several documentation sources including (1) applicable Institute of Nuclear Power Operations (INPO) operating experience reports and documents, (2) NRC IN and other applicable documents, and (3) significant adverse condition reports generated within the company. The program provides for source document receipt, processing (screening, evaluation, and action tracking), and record maintenance of operating experience item disposition. It designates responsible personnel to help assure that operational information originating both from within and outside the company is screened and disseminated and that actions are tracked. It also identifies personnel responsible for helping to ensure that those items screened for evaluation are forwarded to cognizant plant personnel.

The Self-Assessment Program requires individual line organizations to develop annual self-assessment plans and approve completed self-assessments. Self-assessment topics are determined based upon criteria such as identified weaknesses, impact on nuclear safety, and program or process changes. Details of the assessment process, including the requirements for planning, preparation, conduct, and reporting of results to management, are proceduralized.

The staff finds the applicant's response to RAI B.2.4-5 acceptable because the applicant has adequate programs and procedures to upgrade the Steam Generator Tube Integrity Program and they are consistent with GALL XI.M19.

In RAI B.2.4-6, the staff asked the applicant to discuss how SG tube leakage integrity is managed (i.e., the shutdown criteria and guidance when a leak occurs) and describe in detail how tube leakage is monitored at RNP. In its response to RAI B.2.4-6, the applicant stated that the shutdown criterion is leakage greater than or equal to 150 gallons per day through any one SG. Primary-to-secondary leakage may be detected by the radiation monitoring system or by secondary sample analysis. SG samples are analyzed daily for principal gamma emitters and tritium. Gamma emitter activity levels above background indicate a probable leak. When a primary-to-secondary leak is indicated, its magnitude can be determined through secondary coolant chemical analysis. The staff finds the applicant's response to RAI B.2.4-6 acceptable because the applicant's leakage limit is specified in the RNP technical specifications and the leakage monitoring system is consistent with the CLB. The leakage limit and monitoring system are also consistent with GALL XI.M19.

In RAI B.2.4-7, the staff asked the applicant to provide all SG components that are covered under the Steam Generator Tube Integrity Program, other than those components that have been provided in LRA Section B.2.4. In its response to RAI B.2.4-7, the applicant stated that the Steam Generator Tube Integrity Program is credited with aging management of component commodity group items 15 and 17 of Table 3.1-1 and Item 3 of Table 3.1-2 of the LRA. The staff finds the applicant's response to RAI B.2.4-7 acceptable because the components covered in the Steam Generator Tube Integrity Program are consistent with the GALL commodity group.

3.1.2.3.5.3 UFSAR Supplement

In LRA section A.3.1.4, Steam Generator Tube Integrity Program," the applicant provides the UFSAR Supplement summary for the Steam Generator Tube Integrity Program. The UFSAR Supplement description for the program states that the Steam Generator Tube Integrity Program specifies inspection scope, frequency, and acceptance criteria for the plugging and repair of flawed SG tubes in accordance with the plant technical specifications and the guidance of NEI 97-06. Other SG components, in addition to tubes, are also inspected under this program.

In its response to RAI B.1-1, dated April 28, 2003, the applicant stated that it would incorporate the following statement into the UFSAR Supplement summary descriptions for those RNP AMPs that are determined to be consistent with the program attributes of analogous programs in Section XI.M of GALL, Volume 2:

> This program is consistent with the corresponding program described in the GALL Report.

The applicant also stated that the UFSAR Supplement summary statement for those AMPs which take exception to one or more provisions (program attributes) of the corresponding program in GALL, Volume 2, will not incorporate this statement. The applicant's response to RAI B.1-1 indicates that the UFSAR Supplement summary description for the Steam Generator Tube Integrity Program, as given in Section A.3.1.4 of Appendix A of the LRA, will be amended to reflect that the program attributes for the AMP are consistent with those recommended in GALL XI.M19, Steam Generator Tube Integrity." Based on the applicant's response to RAI B.1-1, the staff concludes that the UFSAR Supplement for the Steam Generator Tube Integrity Program is acceptable because it will reflect that the program attributes for the AMP are consistent with the corresponding program attributes recommended by the staff in GALL XI.M19, Steam Generator Tube Integrity."

The staff finds that the summary in the UFSAR supplement is consistent with Section B.2.4, Steam Generator Tube Integrity Program," and is acceptable.

3.1.2.3.5.4 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.6 Reactor Vessel Surveillance Program

The Reactor Vessel Surveillance Program is described in Section B.3.11 of Appendix B of the LRA and is credited with managing aging effects in the upper shell, intermediate shell, lower shell, inlet nozzle, and outlet nozzle of the RNP RV, as well as their associated welds of fabrication.

3.1.2.3.6.1 Summary of Technical Information in the Application

The applicant states the Reactor Vessel Surveillance Program is credited with managing changes in the material properties of the RV materials of fabrication as a result of irradiation embrittlement. The applicant indicates that, as a result of the LR, the Reactor Vessel Surveillance Program will be enhanced to revise RNP procedures to require surveillance test samples to be stored in lieu of disposal.

The applicant indicates that the RNP Reactor Vessel Surveillance Program is implemented in compliance with 10 CFR 50, Appendix H. The applicant states that surveillance capsules have been withdrawn and tested in the past, and the data from these surveillance capsules and data from other industry sources have been used to verify and predict the performance of RNP reactor vessel beltline materials with respect to neutron embrittlement. The applicant indicates that the transient data used in the RNP Reactor Vessel Surveillance Program has been collected since initial plant startup and that the use of the program has been reviewed and approved by the NRC throughout this time.

The applicant states that the Reactor Vessel Surveillance Program is consistent with the corresponding program in GALL XI.M31, "Reactor Vessel Surveillance," with the following exception:

The RNP RCS has been operated for a short period of relatively low temperature. The period of low-temperature operation has been reviewed and accepted previously by the NRC. The effects of the low-temperature operation upon material property projections for the RNP RV materials will be validated upon completion of testing and evaluation of Surveillance Capsule X, to be completed in 2002. Therefore, aging management concerns stemming from this occurrence will be managed, and this is not considered to be an exception.

Therefore, the applicant states that the Reactor Vessel Surveillance Program, with above-described enhancement, is consistent with GALL XI.M31, "Reactor Vessel Surveillance," and that continued implementation of the program provides reasonable assurance that the aging effects will be managed such that the components within the scope of LR will continue to perform their intended functions consistent with the CLB for the period of extended operation.

3.1.2.3.6.2 Staff Evaluation

Part 50 of Title 10 of the *Code of Federal Regulations*, Appendix H, provides the staff's requirements for implementing RV surveillance programs at U.S. light-water reactor facilities. The rule requires licensees owning U.S. light-water reactors to implement an RV surveillance program for each ferritic RV material that is projected to have a neutron fluence exceeding 1×10^{17} n/cm^2 over the licensed periods of operation for the plant. For an RV that meets this criterion, the rule basically requires the licensee to insert material test capsules within the confines of their RV. These material test capsules are to contain samples of the ferritic (low-alloy steel and/or carbon steel) materials that are representative of the materials in the beltline region of the RV, which are expected to be the most limiting with regard to neutron irradiation embrittlement.

Part 50 of Title 10 of the *Code of Federal Regulations*, Appendix H, also requires licensees to remove these capsules for testing at prescribed intervals that meet the withdrawal schedule requirements of ASTM Standard Procedure E185.[7] The rule requires the test results for each surveillance capsule to be submitted in a technical report to the NRC within 1 year of the date of the capsule withdrawal, unless an exemption is granted by the Director of the Office of Nuclear Reactor Regulation. The technical report is required to include the data required by ASTM Standard Procedure E185 and the results of all fracture toughness tests conducted on the beltline materials in the irradiated and unirradiated condition. As required by 10 CFR 50.61, licensees incorporate the results of these RV material surveillance data into the licensee's evaluations for protecting the RV beltline materials against PTS events. Appendix G of 10 CFR Part 50 requires licensees to incorporate these RV material surveillance data into the upper shelf energy assessments for the RV beltline materials and into the plant-specific pressure-temperature limits for the RV.

The AMP defined in GALL XI.M31, "Reactor Vessel Surveillance," gives the criteria and attributes for an acceptable RV surveillance program. The recommended Reactor Vessel Surveillance Program described in GALL XI.M31 basically adjusts the recommended withdrawal schedule criteria in ASTM Standard Procedure E185 to ensure that capsules withdrawn in accordance with the Reactor Vessel Surveillance Program will provide fracture toughness test

[7]Acceptable versions of ASTM Standard Procedure E185 invoked by 10 CFR Part 50, Appendix H, are the version of E185 that is current on the issue date of the ASME Code to which the RV was purchased through versions inclusive of the 1982 version of E185. For each capsule withdrawal, the test procedures and reporting requirements must meet the requirements of E185-82 to the extent practical for the configuration of the specimens in the capsule.

data that is relevant to the operation of the RV through the expiration of the period of extended operation.

The applicant's Reactor Vessel Surveillance Program for the RNP RV is designed in compliance with requirements of 10 CFR Part 50, Appendix H. The applicant states that the Reactor Vessel Surveillance Program for RNP is consistent with the corresponding program in GALL XI.M31, with the exception of the difference described previously in Section 3.1.2.3.4.1 of this SER.

The required withdrawal schedule criteria of ASTM Standard E185-82 are based on estimated fluence exposures, in effective full-power years (EFPY), for the inner surface (ID) and 1/4T locations of the RV. For PTS, the RNP RV is limited by upper circumferential weld 10-273 (Heat W5214), which is represented in the RNP Reactor Vessel Surveillance Program. Since this material has a projected RT_{PTS} shift above 200 °F, the applicant is required by ASTM E185-182 to withdraw five RV surveillance capsules in accordance with the requirements of the standard.

A discussion of the Reactor Vessel Surveillance Program is given in Section 5.3.1 of the RNP UFSAR. The discussion provided in the UFSAR implied that the applicant has already pulled and tested Capsules S, V, Z, and T, in accordance with the requirements of the ASTM standard. However, Footnote 4 of the surveillance withdrawal schedule table provided in UFSAR Section 5.3.1 implies that Capsule V will be reinserted within the RNP RV cavity either before or during the license extension period to support the LRA. Therefore, in order to confirm consistency with the evaluation and technical basis section of GALL XI.M31, the staff issued RAI B.3.11-1 and requested clarifying information on how the withdrawal schedule for remaining Capsules X, U, V, and W would equate to estimated exposures in EFPY for the inner surface and 1/4T locations of the RNP RV during and through the extended period of operation for RNP. The staff also asked the applicant to clarify which of the remaining capsules are required to be withdrawn and tested in accordance with ASTM E185-82, and which of the capsules are considered to be optional capsules for withdrawal and testing. The staff also asked the applicant to clarify whether or not Capsule V will be reinserted into the RV cavity, and if required for withdrawal during the period of extended operation, how the time and position of reinsertion will ensure that the exposures of the capsule will meet the intent of ASTM E185-82 for the extended period of operation.

By letter dated April 28, 2003, the applicant submitted the following response to RAI B.3.11-1.

Capsules S, V, and T have been removed and evaluated as required by the RNP RV Surveillance Program, and the results have previously been reported. The results are documented in the NRC's Reactor Vessel Integrity Database (RVID), Version 2 (with noted comments to RVID, Version 2, provided by letter from R. Warden (CP&L) to NRC, Serial RNP-RA/99-0162, "Comments on Reactor Vessel Integrity Database Data," dated August 27, 1999). A recent UFSAR change has been made to correct errors relating to capsule references and descriptions. Capsule Z was inadvertently removed from the reactor vessel and Capsule Y was inadvertently referred to as Capsule V in the UFSAR.

Capsule X was removed from the reactor vessel during RO-20 in Spring 2001, and the test results are reported in WCAP-15805, "Analysis of Capsule X from Carolina Power and Light Co." This report was submitted by RNP letter from B. L. Fletcher III (CP&L) to the NRC, Serial

RNP-RA/02-0033, "Report of the Analysis of Surveillance Capsule X for the Reactor Vessel Radiation Surveillance Program," dated April 25, 2002.

Capsule X was removed at 20.39 EFPY, with a fluence value of 4.49 x 10^{19} n/cm^2, E> 1.0 MeV. Post-irradiation mechanical tests of the Charpy V-notch and tensile specimens were performed, along with a fluence evaluation. The beltline material test results are compared with the predicted values from Regulatory Guide 1.99, Rev. 2, in WCAP-15805, which includes calculated fluence values at 29 EFPY and 50 EFPY for beltline materials, including inlet and outlet nozzles and welds.

The surveillance capsule removal schedule is included in WCAP-15805 and is provided in Appendix A, Section A.2.1.2, of the LRA. Capsule U will be the fifth capsule removed, which is recommended to occur at approximately 29.8 EFPY exposure (at approximately calendar year 40), with a peak fluence value of 6.00 x 10^{19} n/cm^2, E> 1.0 MeV. This corresponds with the 50 EFPY fluence value projected for the RPV clad/base metal interface at the end of 60 calendar years (per WCAP 15805, Table 6-14). Therefore, Capsule U should provide data representative of the vessel materials at the end of the license renewal period and should demonstrate compliance with 10 CFR Part 50, Appendix G, and ASTM Standard E185-82.

As noted in WCAP-15805, Table 7-1, Capsules Y and W currently lag the vessel peak fluence. Based on the current RNP surveillance plan, as specified in Section 5.3 of the LRA UFSAR Supplement, these two capsules will be repositioned at the end of the current license into lead positions, such that they may be removed for testing during the period of extended operation, if needed. Capsule Y is expected to surpass a fluence value of 6.00 x 10^{19} n/cm^2 at approximately 50 calendar years, and would be available for removal later in the period to obtain relevant fluence data. Capsule W has lower exposure than Capsule Y, and would be available for use beyond the period of extended operation, if needed. Therefore, since additional capsules are available to provide the necessary data during and beyond the period of extended operation, consistent with the recommended RV surveillance capsule withdrawal and testing program outlined in GALL XI.M31, the program is considered consistent with GALL.

The staff confirmed that Capsule X was removed from the RV and that, pursuant to the reporting requirements of 10 CFR Part 50, Appendix H, the results of the fracture toughness and dosimetry tests on the capsule's test specimens were reported by letter from CP&L dated April 25, 2002. WCAP-15805 (March 2002) provides the applicant's safety assessment for the Capsule X dosimetry and fracture toughness test results. The staff assesses the effect of the Capsule X dosimetry and fracture toughness data on the TLAAs for PTS and USE in Sections 4.2.2.1 and 4.2.2.2 of this SER.

The staff reviewed the information in WCAP-15805, as the information relates to the removal and testing of fracture mechanics specimens (i.e., Charpy impact specimens) for Capsule X. The staff determined that, in this report, Westinghouse Electric (the vendor performing the Capsule X analyses on behalf of the applicant) also re-evaluated the dosimetry and Charpy-impact data for all previous capsules removed in accordance with the AMP (i.e., re-evaluated the data for Capsules S, T, and V). WCAP-15805 therefore provides the most up-to-date assessment of the dosimetry and fracture mechanics data for Capsules S, T, V, and X.

Table 7-1 of WCAP-15805 provides the surveillance capsule withdrawal schedule for RNP as it applies to the LR of the facility. The applicant stated that Capsule U is the fifth capsule in the program and will be removed at approximately 29.3 EFPY, and that the neutron fluence projected for this capsule corresponds to the approximate projected limiting neutron fluence of the RV at 50 EFPY. The withdrawal schedule in WCAP-15805 indicates that the in-vessel location for Capsule U was moved sometime within the current life of the plant. Therefore in a meeting dated May 21, 2003, with the applicant (refer to the staff's teleconference summary of May XX, 2003), the staff requested additional clarifying information regarding the elapsed time when Capsule U was moved in the vessel, what the lead factors were for Capsule U at the different in-vessel locations, and what CP&L's basis was for determining that the projected fluence for Capsule U at its projected time of withdrawal would be indicative of the fluence for the RV shell at 50 EFPY (i.e., at the EFPY projected for the end of the extended period of operation for RNP). During the meeting of May 21, 2003, the applicant informed the staff that it would provide the additional information requested by the staff. The applicant submitted the requested information in an email to the staff dated June 9, 2003. The applicant must formally submit the information in the email of June 9, 2003, onto the docket" for RNP (i.e., onto docket for Docket No. 50-261) under Oath and Affirmation." This is Confirmatory Item B.3.11-1.

The applicant has stated that projected fluence (6.00×10^{19} n/cm^2) for Capsule U at its projected time of withdrawal (29.8 EFPY) is equivalent to the project fluence for the RV shell at 50 EFPY (i.e., at the end of the extended period of operation for RNP). The staff reviewed the dosimetry data of WCAP-15805 (i.e., in the surveillance capsule report for Capsule X) for acceptability and determined that the dosimetry methods and calculations in the report were acceptable.

A review of the information for the withdrawal of Capsule U, as given in Table 7-1 of WCAP-15805, indicates that Capsule U has a composite lead factor of 1.68. The staff confirmed that the applicant's information and calculations in the email of June 9, 2003, was consistent with the dosimetry information in WCAP-15805 and provided an acceptable basis for projecting the lead factor for Capsule U. Based on this information and the staff's independent review of the dosimetry data, and the withdrawal schedule in WCAP-15805, the staff concludes that the information obtained from dosimetry data and fracture toughness data of Capsule U test specimens will be indicative of the neutron embrittlement behavior of the RNP RV at the expiration of the extended period of operation. The staff therefore concludes that the proposed withdrawal time for Capsule U is acceptable. Capsules Y and W may be used by the applicant as an additional capsule for removal and testing during the period of extended operation for RNP.

In its response to Confirmatory Item B.3.11-1, dated August 14, 2003, RNP-RA/03-0031, the applicant submitted the information. The information indicates the RV surveillance capsule withdrawal schedule is acceptable for the period of extended operation for RNP, the staff concludes that applicant's response to Confirmatory Item B.3.11-1 is acceptable. Confirmatory Item B.3.11-1 is resolved.

Based on this assessment, the staff concludes that the RV Surveillance Program is consistent with the corresponding program attributes of GALL XI.M31, Reactor Vessel Surveillance Program," for the expiration of the period of extended operation for RNP.

3.1.2.3.6.3 UFSAR Supplement

In Section A.3.1.19 of Appendix A of the LRA, the applicant provides the UFSAR Supplement summary for the Reactor Vessel Surveillance Program. The UFSAR Supplement description for the program states that the Reactor Vessel Surveillance Program uses periodic testing of metallurgical surveillance samples to monitor the progress of neutron embrittlement of the RPV as a function of neutron fluence, in accordance with RG 1.99, Rev. 2, and that, prior to the period of extended operation, the administrative controls for the program will be revised to require surveillance test samples to be stored in lieu of optional disposal.

Reactor vessel surveillance Programs are implemented in accordance with the NRC's requirements in 10 CFR Part 50, Appendix H, Reactor Vessel Materials Surveillance Program Requirements." Therefore, in RAI B.3.11-2, the staff asked the applicant to clarify that the UFSAR Supplement summary description for the Reactor Vessel Surveillance Program will be implemented in accordance with the appropriate requirements of 10 CFR Part 50, Appendix H, for RV materials surveillance programs, and that the data obtained through fracture toughness testing will be used in the applicant's calculations of the time-limited aging analysis calculations of (1) the RNP P-T limits and low temperature overpressure protection (LTOP) limit setpoints, as required by Section IV.A.2 of 10 CFR Part 50, Appendix G, (2) the USE values for the RNP RV beltline materials, as required by Section IV.A.1 of 10 CFR Part 50, Appendix G, and (3) the RT_{PTS} values for the RV beltline materials, as required by 10 CFR 50.61 for PTS evaluations.

By letter dated April 28, 2003, the applicant provided the following response to RAI B.3.11-2:

> The CP&L response to GL 92-01, Revision 1, described how the RNP Reactor Vessel (RV) Surveillance Program met the intent of 10 CFR 50, Appendix H (reference letter from R. Starkey, Jr. (CP&L) to NRC, Serial: NLS-92-179):
>
> Response to GL 92-01, Revision 1, "Reactor Vessel Structural Integrity," dated July 6, 1992. The RV Surveillance Program will be implemented in the same manner during the period of extended operation.

Appendix A, Section 3.1.19, of the LRA, "Reactor Vessel Surveillance Program," will be revised to refer to 10 CFR 50, Appendix H, instead of RG 1.99, Rev. 2. The information in the first paragraph of LRA Subsection A.3.1.19, "Reactor Vessel Surveillance Program," is modified to read:

> Periodic testing of metallurgical surveillance samples is used to monitor the progress of neutron embrittlement of the reactor pressure vessel as a function of neutron fluence, in accordance with 10 CFR 50, Appendix H.
>
> The data obtained through surveillance testing will be used in the determination of the following:
>
> (1) RNP P-T and LTOP limits, as required by Section IV.A.2 of 10 CFR 50, Appendix G (refer to the RNP Response to RAI 4.2.2.3-1 for additional details)
>
> (2) USE values, as required by Section IV.A.1 of 10 CFR 50, Appendix G (refer to the RNP Response to RAI 4.2.2-1 for additional details)
>
> (3) RT_{PTS} values, as required by 10 CFR 50.61, for PTS evaluations (refer to the RNP Response to RAI 4.2.1-1 for additional details)

The applicant's response to RAI B.3.11-2 confirms that the applicant will continue to perform the implementation of the RV Surveillance Program in accordance with the requirements of 10 CFR Part 50, Appendix H, and that any relevant dosimetry data and fracture toughness data obtained through implementation of this AMP will be incorporated in the PTS assessment required by 10 CFR 50.61 and the USE and P-T limit assessments required by 10 CFR Part 50, Appendix G, and amend the UFSAR Supplement summary description for the Reactor Vessel Surveillance Program. Since the applicant's response to RAI B.3.11-2 indicates that the UFSAR Supplement summary description for the AMP will be amended to reflect continued compliance with the appropriate requirements, the staff concludes that the applicant's UFSAR Supplement summary description for the RV Surveillance Program, as given in Section A.3.1.19 of Appendix A of the LRA and amended by the applicant's response to RAI B.3.11-2, is acceptable.

3.1.2.3.6.4 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.3.7 Flux Thimble Eddy Current Inspection Program

The applicant discusses its Flux Thimble Eddy Current Inspection Program in Section B.2.8 of Appendix B of the LRA. The applicant credits this AMP with managing the aging effects applicable to the incore flux thimble tubes. The aging effect/mechanism of concern is loss of material due to wear.

3.1.2.3.7.1 Summary of Technical Information in the Application

The Flux Thimble Eddy Current Inspection Program does not have a corresponding program in GALL, Volume 2. Therefore, the applicant described the program in terms of how the Flux Thimble Eddy Current Inspection Program meets the 10 programs elements stated in the SRP-LR. The applicant's descriptions of the 10 program attributes for the Flux Thimble Eddy Current Inspection Program are provided in detail in Section B.2.8 of Appendix B of the LRA.

3.1.2.3.7.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information for the Flux Thimble Eddy Current Inspection Program, as given in Section B.2.8 of Appendix B of the LRA, to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation. The staff evaluated the Flux Thimble Eddy Current Inspection Program in terms of the following program attributes.

1.1 Scope
1.2 Preventive Actions
1.3 Parameters Monitored or Inspected
1.4 Detection of Aging Effects
1.5 Monitoring and Trending
1.6 Acceptance Criteria
1.7 Administrative Controls
1.8 Confirmatory Actions
1.9 Corrective Actions
1.10 Operating Experience

The application indicated that the corrective actions, confirmatory actions, and administrative controls for license renewal are in accordance with the site-controlled Quality Assurance Program pursuant to 10 CFR Part 50, Appendix B, and cover all SCs subject to an AMR. The staff's evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER. This program satisfies the elements of Corrective Actions, Confirmation Process, and Administrative Controls. The staff's evaluation of the remaining seven program attributes is discussed below.

Scope of Program—The applicant stated that the Flux Thimble Eddy Current Inspection Program is based upon current plant activities delineated in an existing procedure governing flux thimble eddy current inspection. This procedure was implemented by RNP to satisfy NRC Bulletin 88-09 requirements that a tube wear inspection procedure be established and maintained for Westinghouse-supplied reactors which use bottom mounted flux thimble tube instrumentation. The Flux Eddy Current Inspection Program addresses vibration-induced wear in Westinghouse-designed neutron flux instrumentation thimble tubes. Because the staff's discussion in Bulletin 88-09 was limited only to neutron flux thimble tubes in Westinghouse-designed light-water reactors, the staff concurs that the scope of the Flux Thimble Eddy Current Inspection Program is limited only to the monitoring of aging effects in the RNP neutron flux thimble tubes and that no other component need be added to this aging AMP. Based on this determination, the staff concludes that the *Scoping* program attribute for the Flux Thimble Eddy Current Inspection Program is acceptable.

Preventive Actions—The applicant stated that the Flux Thimble Eddy Current Inspection Program is a condition monitoring program; therefore, there are no preventive actions. The staff concurs that the Flux Thimble Eddy Current Inspection is an inspection-based condition monitoring program and that, as such, the program does not include preventive or mitigative actions to preclude the occurrence of an aging effect.

Parameters Monitored/Inspected—The applicant stated that the aging effect to be managed by the Flux Thimble Eddy Current Inspection Program is loss of material due to wear in the double-walled, incore flux thimble tubes. This is consistent with NRC Bulletin 88-09. Therefore, the staff concurs that the Flux Thimble Eddy Current Inspection Program is limited only to the monitoring of wear in the RNP neutron flux thimble tubes.

Detection of Aging Effects—The applicant stated that the Flux Thimble Eddy Current Inspection Program is a periodic volumetric eddy current examination of the double-walled, incore flux thimble tubes. The inspections of the thimble tubes are performed at a variable frequency dependent on extrapolation of wear rates determined from previous inspections.

In NRC Bulletin 88-09, the staff requested that each licensee owning a Westinghouse-designed PWR establish an inspection program to monitor for thimble tube performance and to include in the program the establishment of an inspection methodology that is capable of adequately detecting wear in the thimble tubes (such as eddy current testing (ECT). The applicant's description of the Flux Eddy Current Inspection Program implied that the applicant might use alternative volumetric inspection methods to monitor for wear in the tubes in lieu of using ECT for the examinations. Therefore, in RAI B.2.8-1, the staff asked the applicant to clarify which additional volumetric inspection methods, if any, might be used as alternatives to ECT and how these alternative inspection techniques would be qualified to monitor for vibration-induced wear of the incore neutron flux thimble tubes.

In its response to RAI B.2.8-1, dated April 28, 2003, the applicant clarified that ECT is the method credited for the incore neutron flux thimble tube examinations and that the applicant does not currently credit any other volumetric inspection methods as alternative methods for flux thimbles examinations. Since the applicant's response clarifies that only ECT will be credited for the examinations of the incore neutron flux thimble tubes, the staff considers RAI B.2.8-1 to be resolved.

Monitoring and Trending—The applicant states that the Flux Thimble Eddy Current Inspection Program projects the rate of wear of the double-walled, incore flux thimble tubes, ensuring that timely corrective action will be performed well before failure of any of the tubes due to wear could occur. Additional details of the Flux Thimble Eddy Current Inspection Program are provided in the applicant's response to NRC Bulletin 88-09, dated February 8, 1991. In this response, the applicant provided an acceptable technical basis for supporting ECT of incore flux thimble tubes every other RFO. Based on the technical basis provided in the applicant's response to NRC Bulletin 88-09, the staff concludes that the applicant has provided an acceptable regulatory basis for supporting ECT examinations of the thimble tubes every other RFO.

Acceptance Criteria—The applicant stated that the administrative controls for the Flux Thimble Eddy Current Inspection Procedure provide specific, objective acceptance criteria that ensure that any thimble tube that is expected to experience throughwall wear greater than the ASME criteria specified for the examination prior to the next inspection is removed from service. No subjective analysis that might permit a marginal tube to be returned to service is permitted by the procedure.

In NRC Bulletin 88-09, the staff requested that each licensee owning a Westinghouse-designed PWR establish an inspection program to monitor for thimble tube performance and to include as part of the program the establishment of an appropriate thimble tube wear acceptance criterion (for example, percent throughwall loss). The applicant's response to NRC Bulletin 88-09, dated February 8, 1991, provides additional details regarding the acceptance criterion for the incore flux thimble tube eddy current inspections. In this response, the applicant provides a technically acceptable basis for supporting 65 percent throughwall degradation as the amount of acceptable wear that can occur over two operating cycles for RNP. Based on the information in the applicant's response to NRC Bulletin 88-09, the staff concludes that the applicant's acceptance criterion (i.e., 65 percent throughwall degradation) is acceptable.

Operating Experience—A review of condition reports identified two which involved thimble tubes. Both of the condition reports identified thimble tubes with very small leak rates. The leaks were evaluated under the Corrective Action Program; however, the root cause of leakage could not be determined. The applicant stated that the corrective action for the degraded incore flux thimble tubes involved replacement of the thimble tubes. In RAI B.2.8-2, the staff asked the applicant to summarize the details of any relative age-related operating experience for the incore flux thimble tubes at RNP and to describe how the relevant data from any operating events have been accounted for in the program attributes for the Flux Thimble Eddy Current Inspection Program, as discussed in Section B.2.8 of Appendix B of the LRA and in the applicant's response to NRC Bulletin 88-09, dated February 8, 1991.

By letter dated April 28, 2003, as amended in the letter of June 13, 2003, the applicant provided the following response to RAI B.2.8-2.

The two documented incore flux thimble tube leaks were identified on tubes F-13 and J-07 during 1996 and 1999, respectively. The leakage from F-13 was discovered when RCS coolant was found in the associated tube during eddy current testing, and the leak in J-07 was found after an annunciator activated from water accumulating on the seal table from a slow leak.

While the actual cause and type of degradation for F-13 is unknown, eddy current testing of F-13 indicated 87 percent wear-through in the vicinity of the fuel assembly bottom nozzle, which implies some type of debris-induced fretting. This was determined to be an isolated event and is not indicative of general degradation associated with the incore flux thimbles.

The cause and type of degradation for J-07 could also not be determined. Since eddy current testing revealed no wear for the tube attributed to the leakage, this occurrence is attributed to a microscopic throughwall crack. This is also considered an isolated event and not indicative of any general degradation associated with the incore flux thimbles.

F-13 was capped and removed from service. The leakage attributed to J-07 was determined to be insignificant, so the tube was isolated but remains in service. The eddy current test procedure was revised to caution the user that tube J-07 may contain water due to the leak and that appropriate care should be exercised at the beginning of testing for this tube. This was determined to be the only enhancement required to the Flux Thimble Eddy Current Inspection Program as a result of these events.

The degradation of the F-13 and J-07 incore flux thimble tubes was detected through implementation of the applicant's Flux Thimble Eddy Current Inspection Program and demonstrates that the AMP is accomplishing its intended purpose of detecting age-related degradation in the RNP incore flux thimble tubes. Based on the applicant's summary of the operating experience in its response to RAI B.2.8-2, the staff concludes that the applicant has been implementing its Flux Thimble Eddy Current Inspection Program in accordance with the program described in the applicant's response to NRC Bulletin 88-09 (dated February 8, 1991), and has taken acceptable corrective action to address any age-related degradation that has occurred in the RNP incore flux thimble tubes. The applicant has provided an acceptable response to NRC Bulletin 88-09, and has effectively summarized the operating events requested by the staff and has discussed the corrective actions taken relative to any degradation that has occurred in the RNP incore flux thimble tubes. Therefore, based on the applicant's responses to NRC Bulletin 88-09 and RAI B.2.8-2, the staff concludes that applicant has addressed the impacts of the operating experience for RNP that is relevant to the Flux Thimble Eddy Current Inspection Program, and RAI B.2.8-2 is resolved.

3.1.2.3.7.3 UFSAR Supplement

In Section A.3.1.8 of Appendix A of the RNP LRA, the applicant provides the following UFSAR Summary for the Flux Thimble Eddy Current Inspection Program.

The Flux Thimble Eddy Current Inspection Program is a plant-specific program that determines the amount of wear on the flux thimbles, and whether the amount of wear expected to occur during the next inspection interval will cause the total amount of wear to exceed the ASME standards specified for the examination. The Flux Thimble Eddy Current Inspection Program was implemented to satisfy NRC Bulletin 88-09 requirements that a thimble tube wear inspection procedure be established and maintained for Westinghouse-supplied reactors that use bottom mounted flux thimble tube instrumentation.

The applicant's response to NRC Bulletin 88-09 provides the CLB details for the inspection frequency, flaw acceptance criteria, and inspection methodology of the Flux Thimble Eddy Current Inspection Program. Therefore, in RAI B.2.8-3, the staff requested that the applicant modify its UFSAR Supplement description for the Flux Thimble Eddy Current Inspection Program to reflect the information provided in the CP&L response to Bulletin 88-09, dated February 8, 1991.

In its response to RAI B.2.8-3, dated April 28, 2003, the applicant stated that the UFSAR Supplement summary description for the Flux Thimble Eddy Current Inspection Program would be modified to incorporate the following statement:

> Additional details regarding examination frequency, flaw acceptance criteria, and inspection methodology are provided in the RNP letter from G. Vaughn (CP&L) to NRC, Serial NLS-91-024: "Response to NRC Bulletin No. 88-09," dated February 8, 1991.

Since the applicant's response to RAI B.2.8-3 states that the UFSAR Supplement summary description for the Flux Thimble Eddy Current Inspection Program will be modified to clarify which document contains the CLB for the AMP, the staff concludes that RAI B.2.8-3 is acceptable and RAI B.2.8-3 is resolved.

3.1.2.3.7.4 Conclusions

On the basis of its review of the applicant's program, the staff finds that the program adequately addresses the 10 program elements defined in Branch Technical Position (BTS) RLSB-1 in Appendix A.1 of the SRP-LR, and that the program will adequately manage the aging effects for which it is credited so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 50.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.1.2.4 Aging Management of Plant-Specific Components

Table 3.1-2 of the LRA provides AMRs for RCS components that the applicant has determined are not covered by the scope of corresponding AMR items in GALL, Volume 2, or are not consistent with the scope of corresponding AMR items in GALL, Volume 2. These evaluations include the staff's evaluations of components in the following subsystems:

- reactor coolant system piping
- reactor coolant pumps
- pressurizers
- reactor vessel
- reactor vessel internals
- steam generator
- reactor vessel level instrumentation

The staff evaluates AMRs in Table 3.1-2 for these RCS subsystems in the subsections to SER Section 3.1.2.4 that follow.

3.1.2.4.1 Reactor Coolant System Piping

Table 3.1-2 of the LRA provides AMRs for RCS components that the applicant has determined are not covered by the scope of corresponding AMR items in GALL, Volume 2, or are not consistent with the scope of corresponding AMR items in GALL, Volume 2. The following AMRs in Table 3.1-2 of the LRA include the additional AMRs for RCS piping components:

- AMR Item 2 in which the applicant evaluates loss of material due to crevice or pitting corrosion in austenitic SS or nickel-based alloy RCS components[8] that are exposed internally to treated water or steam
- AMR Item 8 in which the applicant evaluates whether aging effects are applicable for non-Class 1 carbon steel RCS piping, valves, and fittings associated with the pressurizer relief tank
- AMR Item 17 in which the applicant evaluates whether aging effects are applicable for stainless RCS piping, valves, and fittings (including stainless steel valves and fittings associated with the seal table and stainless steel RCS flow orifices and restrictors) that are exposed to indoor not-air-conditioned, containment air, and borated water leakage external environments

[8]The corresponding components listed in AMR 2 of the LRA include (1) clad RCS components, (2) RCS piping, valves, tubes and fittings, (3) RCS seal table valves and fittings, (4) pressurizer nozzle safe ends, (5) pressurizer heaters and penetrations, (6) pressurizer manway inserts, (7) RV nozzle safe ends, (8) CRDM housings, (9) RV flux thimbles and guide tubes, (10) RV core support pads (11) SG divider plate, (12) SG primary manway insert, and (13) SG tubeplate cladding.

- AMR Item 18 in which the applicant evaluates whether aging effects are applicable for stainless steel piping, tubing, and fittings associated with the non-Class 1 RV level instrumentation lines

3.1.2.4.1.1 Crevice or Pitting Corrosion in Stainless Steel or Nickel-Based RCS Components Under Internal Treated Water Environments—Evaluation of AMR Item 2 of LRA Table 3.1-2

Summary of Technical Information in the Application

In AMR Item 2 of Table 3.1-2 of the LRA, the applicant identifies that loss of material due to crevice or pitting corrosion is an applicable aging effect for a number of RCS components, including RCS piping, valve, and fitting components, that are fabricated from SS or nickel-based alloys and are exposed to treated water environments. The applicant identified the scope of the AMR as including the following components.

- RV cladding
- control rod drive housings
- reactor vessel and pressurizer nozzle safe ends
- core support pads
- flux thimbles and guide tubes
- pressurizer heater penetrations
- seal table valves and fittings, valves
- piping, tubing, fittings
- steam generator divider plate
- pressurizer and steam generator primary manway inserts
- steam generator tubeplate cladding

Evaluation—Identification of Aging Effects

Section IV of GALL, Volume 2, does not identify that loss of material due to general corrosion, pitting corrosion, or crevice corrosion is an applicable aging effect for austenitic alloys (such as austenitic SS and nickel-based alloys). The applicant has identified that loss of material due to crevice or pitting corrosion is an applicable aging effect for the SS and nickel-based RCS components listed in the above list in creviced or restricted access regions. This is an additional conservative aging effect relative to the aging effects that are identified in GALL for Class 1 SS and nickel-based alloy components.

In RAI 3.1.2.4.1-1, the staff requested clarification of the specific RCS components that are included under the scope of column 1 to AMR Item 2 in LRA Table 3.1-2. The applicant responded to RAI 3.1.2.4.1-1 by letter dated April 28, 2003, and clarified that the scope of AMR Item 2 to LRA Table 3.1-2 includes the following RCS components, as grouped by plant system (with the GALL commodity group and/or GALL component number given prior to the component description, as applicable):

Primary Sampling System

- Valves, Piping and Fittings

Reactor Vessel and Internals System

- A2.1.1 Dome Cladding
- A2.3.1 Nozzles—Inlet Cladding
- A2.3.2 Nozzles—Outlet Cladding
- A2.5.1 Vessel Shell—Upper Shell Cladding
- A2.5.2 Vessel Shell—Inter. And Lower Shell Cladding
- A2.5.3 Vessel Shell—Vessel Flange Cladding
- A2.5.4 Vessel Shell—Bottom Head Cladding
- A2.4.1 Nozzles—Safe End (Inlet)
- A2.4.2 Nozzles—Safe End (Outlet)
- B2.6.1 Flux Thimble Guide Tubes
- Seal Table Valves and Fittings
- A2.1.2 Head Flange Cladding
- A2.2.2 CRD Head Penetration Pressure Housing
- A2.2.1 CRD Head Penetration Nozzle
- A2.6 Core Support Pads
- A2.7.1 Penetrations—Instrumentation Tubes (Bottom Head)
- A2.7.2 Penetrations—Head Vent Pipe
- B2.6.2 Flux Thimbles
- A2.7.3 Penetrations—Instrumentation Tubes (Top Head)

Reactor Coolant System

- Valves, Piping, Tubing and Fittings
- C2.5-f (C2.5.5, C2.5.6, C2.5.7) PZR Thermal Sleeves, Instrument Nozzle, Safe End
- C2.5-h (C2.5.7) Pressurizer Safe Ends
- C2.5-q, C2.5-r (C2.5.10) Pressurizer Immersion Heater Sheaths/Sleeves
- C2.5-g (C2.5.6) Pressurizer Instrument Nozzles
- C2.5-m (C2.5.8) Pressurizer Manway Insert
- C2.5-a and C2.5-c (C2.5.1) Pressurizer Shell/Heads
- C2.5-d (C2.5.2) Pressurizer Spray Nozzle
- C2.5-e (C2.5.3) Pressurizer Surge Nozzle
- C2.5-g (C2.5.2, C2.5.3) PZR Spray and Surge Nozzles

Residual Heat Removal System

- Valves, Piping, Tubing and Fittings

Chemical and Volume Control System

- Valves, Piping, Tubing and Fittings

Safety Injection System

- Piping and Fittings

Steam Generator System

- D1.1-h (D1.1.8, Lower Head Cladding)
- D1.1-h, D1.1-i (D1.1.9, Primary Nozzles Cladding and Safe Ends)
- Steam Generator Primary Manway Insert
- Steam Generator Lower Head Divider Plate
- Steam Generator Tubeplate Cladding

The applicant's response to RAI 3.1.2.4.1-1 clarifies which RCS components are within the scope of AMR 2 to LRA Table 3.1-2. The applicant's identification that loss of material due to crevice or pitting corrosion as an applicable aging effect for these SS and nickel-based RCS components is a conservative AMR that supplements the AMRs given for the RCS in Section IV of GALL, Volume 2. Based on the assessment, that staff concludes that the applicant's AMR for evaluating loss of material due to crevice or pitting corrosion in nickel-based alloy or SS RCS components is acceptable and RAI 3.1.2.4.1-1 is resolved.

Evaluation—Aging Management Programs

Except for cladding, the applicant has proposed to use the Water Chemistry Program as the sole program for managing loss of material in the components listed within the scope of column 1 to Item 2 of LRA Table 3.1-2. The applicant considers this acceptable because, according to the applicant's assessment, Section IV of GALL, Volume 2, does not identify that austenitic SS or nickel-based alloy components in the RCS are susceptible to general corrosion, pitting corrosion, and crevice corrosion under exposure to borated water environments. The applicant also states that the implementation of hydrogen water chemistry establishes a hydrogen concentration for the RCS that ensures that corrosion is nonsignificant for the internal surfaces of the RNP pressurizer, as well as for the internal surfaces of other Class 1 components. The applicant states that hydrogen concentration limits for the RCS are delineated in the Water Chemistry Program. The applicant therefore considers that the Water Chemistry Program is the only program that needs to be credited to manage loss of material due to general, crevice, and pitting corrosion in these RCS components (except for the cladding of the lower head of the RNP SGs). For cladding in the lower head of the SGs, the ASME Section XI, Subsections IWB, IWC, and IWD Program has been credited together with Water Chemistry Program.

The staff has previously accepted hydrogen water chemistry as a mitigative basis for minimizing the effects of general, crevice, or pitting corrosion in Class 1 pressurizer components that are exposed to borated treated water (refer to the staff's safety evaluation dated October 26, 2002, ADAMS Accession Number ML003763768). The applicant is basing management of general, crevice, and pitting corrosion in the internal surfaces of Class 1 components that are exposed to borated treated water on the implementation of hydrogen water chemistry, which is implemented as part of the applicant's Water Chemistry Program. The staff does not have any issues with using hydrogen water chemistry as the basis for managing loss of material due to general, pitting, and crevice corrosion in Class 1 components. However, the staff requested, in RAI 3.1.2.4.1-2, that the applicant provide a basis as to how implementation of RNP's Water Chemistry Program is sufficient to provide for a level of hydrogen overpressure that is capable of managing crevice or pitting corrosion in the internal surfaces of the Class 1 RCS components that are exposed to the borated reactor coolant.

The applicant provided the following response to RAI 3.1.2.4.1-2 by letter dated April 28, 2003:

> RNP does not credit WCAP-14574 in the LRA for Class 1 RCS components. Therefore, a specific response for Action Item 3.2.2.1-1 of the safety evaluation is not required. However, hydrogen concentrations in the RNP RCS are strictly maintained within specified limits by measurement of hydrogen concentrations in periodic RCS samples, and adjusting hydrogen overpressure in the volume control tank accordingly. The hydrogen concentration limits established for the RCS ensure that corrosion is non-significant for the internal surfaces of the RNP pressurizer as well as other Class 1 components. This is stated in LRA Table 3.1-2, Item 2. As discussed in LRA, B.2.2 (Water Chemistry Program), the overall effectiveness of the Water Chemistry Program is supported by the operating experience for systems, structures and components, which are influenced by the Water Chemistry Program. No chemistry-related degradation has resulted in loss of component intended functions on systems for which the fluid chemistry is actively controlled.

The applicant's response to RAI 3.1.2.4.1-2 indicates that the applicant will ensure that an acceptable concentration of dissolved hydrogen will be maintained in the RCS coolant through implementation of its Water Chemistry Program. The applicant implements this program in accordance with applicable EPRI PWR Water Chemistry Guidelines. Since the applicant will be implementing the Water Chemistry Program to maintain an acceptable level of dissolved hydrogen in the RCS coolant, the staff concludes that the Water Chemistry Program will provide an acceptable mitigative method of managing loss of material due to pitting, general corrosion, or crevice corrosion in the SS or nickel-based Class 1 piping components during the period of extended operation for RNP. The staff therefore concludes that AMR Item 2 to LRA Table 3.1-2 is acceptable, and RAI 3.1.2.4.1-2 is resolved.

Conclusions

AMR Item 2 to LRA Table 3.1-2 is an alternative AMR to corresponding AMRs discussed in the GALL Report for management of general, pitting, and crevice corrosion in Class 1 piping components. Based on the staff's review of the applicant's analysis, as supplemented by the applicant's response to RAIs 3.1.2.4.1-1 and 3.1.2.4.1-2, the staff finds that the applicant has provided an acceptable basis for concluding that the Water Chemistry Program is sufficient to manage general corrosion, pitting corrosion, and crevice corrosion in the surfaces of the SS or nickel-based alloy components in the RCS that are in chemically treated borated water. On the basis of its review, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.1.2.4.1.2 Aging Effects for Carbon Steel Non-Class 1 Piping, Valve and Fitting Components in Air or Gas Environments–Evaluation of AMR Item 8 of LRA Table 3.1-2

Summary of Technical Information in the Application

In AMR Item 8 of Table 3.1-2 of the LRA, the applicant provides its AMR for carbon steel non-Class 1 piping, valve, and fitting components that are exposed to air and gas environments. The applicant stated that this component/commodity group consists of valves, piping, and fittings associated with piping connected to the pressurizer relief tank. The applicant also stated that the pressure relief tank is provided with a blanket of nitrogen gas and that, therefore, these components are subject to a dry, inert environment on their internal surfaces. The applicant concluded that these valves, piping, and fitting components have no aging effects resulting from this environment.

Evaluation—Identification of Aging Effects

Column 3 of AMR 8 of LRA Table 3.1-2 stated that the scope of the AMR included air and gas environments for carbon steel non-Class 1 piping, valve, and fitting components, but did not clarify whether these environments were internal or external. However, in the discussion column for AMR 8 of LRA Table 3.1-2, the applicant only discussed the potential for aging to occur under exposure to an internal, dry nitrogen environment. Therefore, it was not apparent to the staff whether the scope of the AMR addressed the potential for aging to occur in these components under exposure to external air or gas environments.

In RAI 3.1.2.4.1-3, the staff requested further clarification as to whether the applicant had performed an AMR for this commodity group for the exposure of the components within this commodity group to external air or gas environments. If an AMR was performed for the surfaces of components in this commodity group that are exposed to external air or gas environments, the staff requested further clarification of which table and AMR item provided the AMR analysis for these components under the air or gas environments. If an AMR had not been performed, the staff asked the applicant to submit an additional AMR for the carbon steel or low-alloy steel RCS piping, valve, and fitting components that are within this commodity group and are exposed to external air or gas environments, and to identify all applicable aging effects for these components. The staff asked the applicant to clarify which AMPs will be credited for these components, if aging effects are determined to be applicable for these components under external air or gas environments.

In its response to RAI 3.1.2.4.1-3, dated April 28, 2003, the applicant clarified that the scope of the AMR analysis in Item 8 of LRA Table 3.1-2 is only applicable to the surfaces on non-Class 1 piping components that are exposed internally to air or gas environments and that the corresponding AMR analysis for the surfaces exposed to external air or gas environments is given in AMR Item 26 to Table 3.1-1 of the LRA. The staff evaluates AMR Item 26 of LRA Table 3.1-1 in Section 3.1.2.1 of this SER.

Based on the discussion provided in Item 8 of LRA Table 3.1-2 and this clarification, it is evident that the AMR analysis for Item 8 of LRA Table 3.1-2 applies only to exposure of the components under an internal dry, inert-nitrogen environment. Carbon steel is not subject to oxidative reactions under exposure to this environment. Based on this assessment, the staff concurs that there will not be any applicable aging effects for the surfaces on the non-Class 1 carbon steel piping components which are exposed to these conditions. The staff therefore concludes that the applicant's analysis provided in AMR Item 8 of LRA Table 3.1-2 is acceptable and RAI 3.1.2.4.1-3 is resolved.

Evaluation—Aging Management Programs

In the "Evaluation—Aging Effects" section for AMR Item 8 of LRA Table 3.1-2, the staff provided an acceptable basis for concluding that aging effects are not applicable for the surfaces of carbon steel non-Class 1 components that are exposed internally to dry, inert-nitrogen environments. Based on the assessment given in the "Evaluation—Aging Effects" section for this AMR item, the staff concurs that aging management is not necessary for the surfaces of carbon steel non-Class 1 components that are exposed internally to dry, inert-nitrogen environments.

Conclusions

AMR Item 8 of LRA Table 3.1-2 provides a supplemental AMR for assessing whether aging effects are applicable for the internal surfaces of non-Class 1 carbon steel piping components that are exposed to air or gas environments. Based on the staff's review of the applicant's analysis, as supplemented by the applicant's response to RAI 3.1.2.4.1-3, the staff finds the applicant has provided an acceptable basis for concluding that there are no applicable aging effects for the surfaces of the carbon steel non-Class 1 piping components that are exposed internally to dry nitrogen gas. On the basis of this review, the staff concludes that the applicant has demonstrated that aging management is not necessary during the period of extended operation.

3.1.2.4.1.3 Aging Effects for Stainless Steel Reactor Coolant Pump Piping, Valve and Fitting Components Under External Indoor Not-Air-Conditioned, Containment Air, and Borated Water Leakage Environments—Evaluation of AMR Item 17 of LRA Table 3.1-2

Summary of Technical Information in the Application

In AMR Item 17 of LRA Table 3.1-2, the applicant evaluates whether aging effects are applicable for stainless RCS piping, valves, and fittings (including SS valves and fittings associated with the seal table and SS RCS flow orifices and restrictors) that are exposed to indoor not-air-conditioned, containment air, and borated water leakage external environments. In this AMR, the applicant concluded that there no applicable aging effects for the surfaces of the RCS piping, valve, and fitting components that are exposed to these external environments and stated that boric acid is not an aggressive chemical species for SS.

Evaluation—Identification of Aging Effects

The applicant stated the scope of AMR 17 of LRA Table 3.1-2 is applicable to the surfaces of SS RCS components that are exposed to indoor not-air-conditioned or containment air environments. However, in RAI 3.1.2.4.1-4, the staff informed the applicant that Column 1 of AMR Item 17 of LRA Table 3.1-2 did not clearly indicate which RCS piping, valve, and fitting components are within the scope of the AMR and requested confirmatory clarification as to which components were considered by the applicant to be within the scope of AMR Item 17 of LRA Table 3.1-2.

In its response to RAI 3.1.2.4.1-4, dated April 28, 2003, the applicant clarified that the scope of AMR Item 17 to LRA Table 3.1-2 includes the following SS RCS components:

Reactor Coolant System

- stainless steel sealable valves and fittings
- stainless steel flow orifices/elements within the RCS
- stainless steel valves, piping, tubing, and fittings within the RCS

Class 1 Portions of the Residual Heat Removal System

- stainless steel valves, piping, tubing, and fittings within the RHR system

Class 1 Portions of the Chemical and Volume Control System

- stainless steel flow orifices/elements within the CVCS
- stainless steel valves, piping, tubing, and fittings within the RCS

Reactor Vessel Level Instrumentation System

- stainless steel valves, piping, tubing, and fittings within the reactor vessel level instrumentation system

The applicant's response to RAI 3.1.2.4.1-4 clarifies which components are within the scope of AMR 17 of LRA Table 3.1-2 and is therefore acceptable. RAI 3.1.2.4.1-4 is resolved.

In AMR 17 of LRA Table 3.1-2, the applicant also concluded that there were no applicable aging effects for the external surfaces of the SS RCS piping, valve, and fitting components that are exposed to indoor not-air-conditioned or containment air environments. The applicant, however, did not provide any technical basis for making this conclusion. Therefore, in RAI 3.1.2.4.1-5, the staff asked the applicant to provide its technical basis why it did not consider aging effects (i.e., loss of material and/or cracking) to be applicable for the external surfaces of SS RCS piping, valve, and fitting components (including tubes, orifices, and flow restrictors) that are exposed to either the indoor not-air-conditioned or containment air environments.

The applicant provided the following response to RAI 3.1.2.4.1-5 by letter dated April 28, 2003:

> The specific components within the scope of LRA Table 3.1-2, Item 17, are described in the RNP Response to RAI 3.1.2.4.1-4. Consistent with GALL, no aging effects/mechanisms have been identified for the external surfaces of these stainless steel components. The RNP aging management review considered material, environment, and operating parameters for the subject components and is based upon industry guidance and plant specific experience regarding aging effects of stainless steel components.

The applicant's response to RAI 3.1.2.4.1-5 indicates that the applicant is basing its aging effect determination on the fact that Section IV.C2 of GALL, Volume 2, does not identify loss of material due to general corrosion or aggressive corrosive attack from boric acid as an applicable aging effect for SS components in the RCS. While the applicant's technical basis in its response to RAI 3.1.2.4.1-5 was limited to the fact that GALL does not identify loss of material due to general corrosion or aggressive chemical attack as an applicable aging effect for these components, the staff concurs that austenitic SS grades in PWR-designed light-water reactors are designed to be resistant to loss of material that may result from either general corrosion or from aggressive corrosive attack from boric acid, and therefore concludes that neither general corrosion nor wastage (i.e., a form of loss of material) from leaks of borated coolants are applicable aging effects for the external surfaces of SS RCS piping, valve, and fitting components (including tubes, orifices, and flow restrictors) that may be exposed to leaks of borated treated water. This assessment gives the basis why the GALL Report does not identify loss of material as an applicable aging effect for the surfaces of SS components that may be exposed to leaks of borated aqueous coolants or even to moist or humid air environments. Based on this assessment, the staff concludes that the applicant has provided an acceptable basis for concluding that loss of material due to general corrosion or aggressive chemical attack is not an applicable aging effect for the surfaces of Class 1 SS piping components under external environments. RAI 3.1.2.4.1-5 is resolved.

Evaluation—Aging Management Programs

In the "Evaluation—Aging Effects" section for AMR Item 17 of LRA Table 3.1-2, the staff provided an acceptable basis for concluding that aging effects are not applicable for the surfaces of SS Class 1 piping components that are exposed to external environments. Based on the assessment given in the "Evaluation—Aging Effects" section for this AMR item, the staff concurs that aging management is not necessary for the surfaces of SS Class 1 piping components that are exposed to external environments.

Conclusions

AMR Item 17 of LRA Table 3.1-2 provides a supplemental AMR for assessing whether aging effects are applicable for the external surfaces of Class 1 SS piping components that are exposed to external indoor environments. Based on the staff's review of the applicant's analysis, as supplemented by the applicant's responses to RAIs 3.1.2.4.1-4 and 3.1.2.4.1-5, and the staff's independent assessment of this AMR Item, the staff finds that the applicant has provided an acceptable basis for concluding that there are no applicable aging effects for the surfaces of the SS Class 1 piping components under these environments. On the basis of this review, the staff concludes that the applicant has demonstrated that aging management is not necessary during the period of extended operation.

3.1.2.4.1.4 Aging Effects for Stainless Steel RCS Piping, Valve, and Fitting Components Under External Indoor Not-Air-Conditioned, Containment Air, and Borated Water Leakage Environments—Evaluation of AMR Item 18 of LRA Table 3.1-2

Summary of Technical Information in the Application

In AMR Item 18 of LRA Table 3.1-2, the applicant evaluates whether aging effects are applicable for stainless RCS piping, tubes, and fittings in the non-Class 1 RV instrumentation lines that are exposed internally to treated water or steam. In RAI 3.1.2.4.1-6, the staff requested confirmation that the scope of AMR Item 18 of LRA Table 3.1-2 is limited only to the piping, tubes, and fittings in the non-Class 1 RV instrumentation lines.

In its response to RAI 3.1.2.4.1-6, the applicant confirmed that AMR 18 of LRA Table 3.1-2 is limited only to the piping, tubes, and fittings in the non-Class 1 RV instrumentation lines and, therefore, RAI 3.1.2.4.1-6 is resolved.

Evaluation—Identification of Aging Effects

In AMR 18 of LRA Table 3.1-2, the applicant concluded that there no applicable aging effects for the surfaces of the SS piping, tube, and fitting components in the RV instrumentation lines that are exposed internally to treated water or steam environments. The applicant based its conclusion on its determination that the RV instrumentation line components are isolated from other components in the RCS that are exposed internally to treated water, and that instead, the

RV instrumentation line components are exposed internally only to purified deionized water.

In RAI 3.1.2.14-7, the staff requested confirmation from the applicant that the environmental conditions for the components with RAI Item 18 of LRA Table 3.1-2 are limited to purified, deionized water. In its response to RAI 3.1.2.4.1-6 the applicant confirmed that environmental conditions for AMR 18 of LRA Table 3.1-2 are limited only to exposure of the components within the AMR to purified deionized water and, therefore, RAI 3.1.2.4.1-7 is resolved.

Austenitic SS materials are designed to be resistant to corrosion in purified deionzied water. The staff therefore concurs that aging effects are not applicable for the internal surfaces of the SS piping, tube, and fitting components in the RV instrumentation lines. Based on this assessment, the staff concludes that AMR 18 of LRA Table 3.1-2 is acceptable.

Evaluation—Aging Management Programs

In the "Evaluation—Aging Effects" section for AMR Item 18 of LRA Table 3.1-2, the applicant provided an acceptable basis for concluding that aging effects are not applicable for the internal surfaces of SS non-Class 1 piping, tube, and fitting components in the RV instrumentation lines that are exposed to a pure deionized water environment. Based on the assessment given in the "Evaluation—Aging Effects" section for this AMR item, the staff concurs that aging management is not necessary for the internal surfaces of these components.

Conclusions

AMR Item 18 of LRA Table 3.1-2 provides a supplemental AMR for assessing whether aging effects are applicable for the internal surfaces of non-Class 1 SS piping, tube, and fitting components in the RV level instrumentation lines that are exposed to a pure deionized water environment. Based on the staff's review of the applicant's analysis, as supplemented by the applicant's responses to RAIs 3.1.2.4.1-6 and 3.1.2.4.1-7, and the staff's independent assessment of this AMR item, the staff finds that the applicant has provided an acceptable basis for concluding that there are no applicable aging effects for the internal surfaces of the SS non-Class 1 piping, tube, and fitting components in the RV level instrumentation lines under this environment. On the basis of this review, the staff concludes that the applicant has demonstrated that aging management is not necessary during the period of extended operation.

3.1.2.4.2 Reactor Coolant Pumps

Table 3.1-2 of the LRA provides AMRs for RCS components that the applicant has determined are not covered by the scope of corresponding AMR items in GALL, Volume 2, or are not consistent with the scope of corresponding AMR items in GALL, Volume 2. The applicant's AMRs in Table 3.1-2 of the LRA do not include any additional AMRs for the RNP RCP casings fabricated from CASS. The staff's evaluation of the applicant's AMR for evaluating loss of fracture toughness in the RNP RCP casings is given in the staff's evaluation of AMR Item 19 to LRA Table 3.1-1, as given in Section 3.1.2.1 of this SER. The staff's evaluation of the applicant's AMR for evaluating cracking due to SCC in the RNP RCP casings is given in the staff's evaluation of AMR Item 10 to LRA Table 3.1-1, as given in Section 3.1.2.2.7 of this SER.

3.1.2.4.3 Pressurizer

Table 3.1-2 of the LRA provides AMRs for RCS components that the applicant has determined are not covered by the scope of corresponding AMR items in GALL, Volume 2, or are not consistent with the scope of corresponding AMR items in GALL, Volume 2. The following AMRs in Table 3.1-2 of the LRA include the additional AMRs for the RCS pressurizer components:

- AMR Item 2 in which the applicant evaluates loss of material due to crevice or pitting corrosion in austenitic SS or nickel-based alloy RCS components that are exposed internally to treated water or steam

- AMR Item 13 in which the applicant evaluates the applicable aging effects for the internal surfaces of the pressurizer relief tank, which is fabricated from carbon steel

3.1.2.4.3.1 Crevice or Pitting Corrosion in Stainless Steel or Nickel-Based Reactor Coolant System Components Under Internal Treated Water Environments—Evaluation of AMR Item 2 of LRA Table 3.1-2

In AMR Item 2 of Table 3.1-2 of the LRA, the applicant identifies that loss of materials due to crevice or pitting corrosion is an applicable aging effect for a number of RCS components that are fabricated from SS or nickel-based alloys and are exposed to treated water environments. These components include pressurizer nozzle safe ends, pressurizer heater penetrations, and pressurizer manway inserts. The staff's evaluation of AMR Item 2 of LRA Table 3.1-2 is provided in SER Section 3.1.2.4.1.1.

3.1.2.4.3.2 Aging Effects for the Pressurizer Relief Tank Under Internal Treated Water/Steam Environments—Evaluation of AMR Item 13 of LRA Table 3.1-2

Summary of Technical Information in the Application

In AMR Item 13 of LRA Table 3.1-2, the applicant evaluates the aging effects that are applicable to the pressurizer relief tank under internal treated water/steam environments.

Evaluation—Identification of Aging Effects

As a comparison to the applicant's AMR for the pressurizer relief tank, Section IV.C2 of GALL, Volume 2, provides three AMRs for pressurizer relief tanks. AMR Item IV.C2.6-a of GALL, Volume 2, states that fatigue is an applicable effect for pressurizer relief tanks that are fabricated from carbon steel material and clad internally with austenitic SS and that are exposed internally to chemically treated borated water. AMR Item IV.C2.6-b of GALL, Volume 2, states that loss of material due to boric acid corrosion is an applicable effect for external surfaces of pressurizer relief tanks fabricated from carbon steel material that can be exposed to leaks of chemically treated borated water from the pressurizer relief tanks. AMR Item IV.C2.6-c of GALL, Volume 2, states that crack initiation and growth due to SCC are applicable aging effects for the internal surfaces of pressurizer relief tanks that are fabricated with carbon steel material and clad internally with austenitic SS and are exposed to chemically treated borated water.

AMR Item 13 of LRA Table 3.1-2 provides the applicant's AMRs for the pressurizer relief tank. In this AMR, the applicant identified that the pressurizer relief tank at RNP differs from the corresponding pressurizer relief tanks discussed in Section IV.C2 of GALL, Volume 2, in that the pressurizer relief tank at RNP is a carbon steel structure that does not include austenitic SS cladding. Instead the internal surfaces of RNP pressurizer relief tank are lined with a protective coating. The applicant identified that the following four mechanisms may lead to loss of material for the internal surfaces of the RNP pressurizer relief tank—(1) aggressive chemical attack due to exposure to the borated treated water, (2) crevice corrosion, (3) general corrosion, and (4) pitting corrosion. Carbon steel and low-alloy steel components may be susceptible to these aging effect mechanisms under exposure to borated treated water. Industry experience has not yet demonstrated that SCC is a concern for carbon steel or low-alloy steel components in treated water environments. The staff concurs that these aging effects are the applicable corrosive aging effects for the internal surfaces of the pressurizer relief tank because the applicant does not credit the protective coating with protection of the carbon steel surfaces against exposure to borated treated water.

As has been stated previously, AMR Item IV.C2.6-a of GALL, Volume 2, states that fatigue is an applicable effect for pressurizer relief tanks that are fabricated from carbon steel material and are exposed internally to chemically treated borated water. In contrast to the staff's AMR provided in AMR Item IV.C2.6-a of GALL, Volume 2, the applicant did not provide, in either Table 3.1-1 or 3.1-2 of the LRA, an AMR which listed fatigue as an applicable aging effect for the pressurizer relief tanks. In RAI 4.1.2.4.3-1, the staff asked the applicant to provide its technical basis for the conclusion that fatigue is not an applicable aging effect for the internal surfaces of the RNP pressurizer relief tank that are exposed to chemically treated borated water.

The applicant provided the following response to RAI 3.1.2.4.3-1 by letter dated April 28, 2003:

> The normal operating temperature of the pressurizer relief tank is less than 150 °F. Therefore, fatigue is not considered to be an applicable aging effect.

The applicant's response to RAI 3.1.2.4.3-1 indicates that the applicant is using the low operating temperature of the pressurizer relief tank as its basis for concluding that thermal fatigue is not an applicable aging effect for the internal surfaces of the pressurizer relief tank that are exposed to treated water.

The staff concurs that the operating temperatures for the pressurizer relief are not high enough (i.e., less than 150 °F) to the point the temperature fluctuations would be of a concern with respect to the initiation and growth of thermal fatigue cracks. Based on this analysis, the staff concludes that the applicant has provided an acceptable alternative to the AMR in GALL commodity group item IV.C2.6-a of GALL, Volume 2, and an acceptable basis for concluding that crack initiation and growth is not an applicable aging effect as a result of thermal fatigue.

AMR Item IV.C2.6-b of GALL, Volume 2, states that loss of material due to boric acid corrosion is an applicable effect for external surfaces of pressurizer relief tanks fabricated from carbon steel material which can be exposed to leaks of chemically treated borated water from the pressurizer relief tanks. In RAI 3.1.2.4.3-2, the staff requested confirmation that loss of material from the external surfaces of the RNP pressurizer relief tank due to leakage of the borated treated water is addressed under the scope of AMR Item 26 in Table 3.1-1 of the LRA.

In its response to RAI 3.1.2.4.3-2, the applicant confirmed that AMR Item 26 of LRA Table 3.1-1 provides the applicant's AMR for managing the external surfaces of the pressurizer relief tank against aggressive chemical attack (i.e., against leaks of the borated treated water) and, therefore, RAI 3.1.2.4.3-2 is resolved. The staff evaluates AMR Item 26 in Table 3.1-1 of the LRA in Section 3.1.2.1 of this SER.

Based on this assessment, the staff concludes that AMR Item 13 of LRA Table 3.1-2 is an acceptable alternative AMR for the internal surfaces of the pressurizer relief tank that are exposed to borated treated water. Based on this assessment, the staff concludes that the applicant has identified the applicable aging effects for these surfaces (i.e., loss of material due to aggressive chemical attack, from exposure to the borated treated water, crevice, general, and/or pitting corrosion) and that the alternative AMR provided in Item 13 of LRA Table 3.1-2 is acceptable.

<u>Evaluation—Aging Management Programs</u>

The applicant has credited the preventive maintenance activities with managing loss of material in the internal surfaces of the pressurizer relief tank. The preventive maintenance activities are discussed in Section B.3.18 of Appendix B to the LRA. The preventive maintenance activities provide instructions for monitoring structures, systems, and components to permit early detection of degradation. Inspection and testing activities monitor various parameters including surface condition, loss of material, presence of corrosion products, and signs of cracking. The staff evaluates the preventive maintenance activities in Section 3.0.3.12 of this SER.

<u>Conclusions</u>

AMR Item 13 to LRA Table 3.1-2 is an alternative AMR to corresponding AMRs discussed in the GALL Report for management of aging effects for the internal surfaces of the pressurizer relief tank (i.e., as an alternative to the AMRs for the pressurizer relief tank in Section IV.C2 of GALL, Volume 2). The staff finds that the applicant has adequately evaluated the management of loss of material due to either aggressive chemical attack, general corrosion, pitting corrosion, or crevice corrosion for the internal surfaces of the pressurizer relief tank. On the basis of this review, the staff concludes that the applicant has demonstrated that these aging effects will be adequately managed so that the intended function will be maintained consistent with the CLB during the period of extended operation.

3.1.2.4.4 Reactor Vessel

Table 3.1-2 of the LRA provides AMRs for RCS components that the applicant has determined are not covered by the scope of corresponding AMR items in GALL, Volume 2, or are not consistent with the scope of corresponding AMR items in GALL, Volume 2. The following AMRs in Table 3.1-2 of the LRA include the additional AMRs for RNP RV components:

- AMR Item 1 in which the applicant evaluates the loss of preload due to stress relaxation in the carbon steel RV stud assembly components

- AMR Item 2 in which the applicant evaluates loss of material due to crevice or pitting corrosion in austenitic SS or nickel-based alloy RCS components that are exposed internally to treated water or steam

- AMR Item 10 in which the applicant evaluates cracking due to SCC in the RV bottom head instrument penetration tubes that are fabricated from nickel-based alloy and are exposed to the treated borated water in the primary coolant

3.1.2.4.4.1 Loss of Preload Due to Stress Relaxation in Carbon Steel RV Stud Assembly Components—Evaluation of AMR Item 1 in LRA Table 3.1-2

Summary of Technical Information in the Application

Section IV.A2 of GALL, Volume 2, does not address loss of preload due to stress relaxation in the RV closure stud assembly components of PWR-designed light-water reactors. In AMR Item 1 of Table 3.1-2 of the LRA, the applicant identifies that the RV stud assembly components are fabricated from carbon steel and are exposed to containment air and potential borated water leakage environments. Although GALL, Volume 2, does not address loss of preload due to stress relaxation in RV stud assembly components, the applicant has identified that loss of preload due to stress relaxation is an applicable effect for the RV stud assembly components at RNP.

Evaluation—Identification of Aging Effects

The RV stud assembly comprises the RV flange and RV bolts and studs. The bolts are preloaded to maintain the structural integrity of the vessel during normal operations. The amount of preload imparted to the bolts may diminish over time as a result of stress relaxation, which is a creep-related phenomenon. This potential aging effect may loosen the bolts over time and result in a loss of integrity at the bolted connection. Loss of preload is therefore an applicable aging effect for these components. The applicant has identified that loss of preload is an applicable aging effect for the RV stud assembly. This is consistent with the staff's evaluation in GALL for other bolted connections in the RCS (e.g., in the staff's evaluation in Item IV.C2.4-c of GALL, Volume 2, for loss of preload/stress relaxation in RV internal baffle/former bolts) and is therefore acceptable.

Evaluation—Aging Management Programs

The applicant credits the Reactor Head Studs Closure Program as the AMP for managing stress relaxation in the RV stud assembly components. The applicant describes the Reactor Head Studs Closure Program in Section B.2.3 of the LRA. The staff evaluates the ability of the Reactor Head Studs Closure Program to manage loss of preload/stress relaxation in the RV studs assembly components in Section 3.1.2.3.1 of this SER.

Conclusions

AMR Item 1 of LRA Table 3.1-2 provides a supplemental AMR for assessing whether loss of preload due to stress relaxation is an applicable aging effect for the RV head closure studs. Based on the staff's review of the applicant's analysis and the staff's independent assessment of this AMR item, the staff finds that the applicant has provided an acceptable basis for concluding that loss of preload due to stress relaxation is an applicable aging effect requiring aging management for the RV head closure studs. On the basis of this review, the staff concludes that the applicant has demonstrated that loss of preload due to stress relaxation will be managed so that the intended function will be maintained consistent with the CLB in the RV head closure studs during the period of extended operation at RNP.

3.1.2.4.4.2 Crevice or Pitting Corrosion in Stainless Steel or Nickel-Based RCS Components Under Internal Treated Water Environments—Evaluation of AMR Item 2 of LRA Table 3.1-2

In AMR Item 2 of Table 3.1-2 of the LRA, the applicant identifies that loss of material due to crevice or pitting corrosion is an applicable aging effect for a number of RCS components that are fabricated from SS or nickel-based alloys and are exposed to treated water environments. These components include the RV cladding, control rod drive housings, and RV nozzle safe ends. The staff's evaluation of AMR Item 2 of LRA Table 3.1-2 is provided in SER Section 3.1.2.4.1.1.

3.1.2.4.4.3 Cracking Due to SCC in RV Bottom Head Instrument Penetration Tubes—Evaluation of AMR Item 10 in LRA Table 3.1-2

Summary of Technical Information in the Application

The applicant provides its AMR for cracking of the nickel-based alloy RV BMI nozzles under internal exposure to the borated treated water or steam environments in AMR Item 10 of Table 3.1-2 of the LRA.

Evaluation—Identification of Aging Effects

In AMR Item 10 of Table 3.1-2, the applicant identified that cracking due to SCC is the applicable aging effect for the RV bottom head instrumentation tubes under these environments. In AMR Item IV.A2.7-a of GALL, Volume 2, the staff identified that crack initiation and growth due to PWSCC are applicable aging effects for Alloy 600 BMI nozzles and stated that either a plant-specific AMP is to be proposed to manage these effects, or an applicant is to indicate that it will participate in industry-wide programs that will evaluate and determine the appropriate type of AMPs that will be used to manage crack initiation and growth in these components. Industry experience has demonstrated that PWSCC can occur in Alloy 600 components (e.g., SG tubes or CRDM penetration nozzles in PWRs) in spite of controlled maintenance of reactor coolant chemistry. Since PWSCC is a form of SCC, the staff concurs with the applicant that SCC is an applicable aging effect for the RNP BMI nozzles that are exposed internally to the chemically treated borated water environment, and therefore concludes that the applicant's identification that SCC is an applicable aging effect for the RNP BMI nozzles is acceptable.

Evaluation—Aging Management Programs

The applicant has credited the Chemistry Control Program and the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program with managing SCC in the BMI nozzles during the extended period of operation for RNP. In contrast, according to Section IV.A2.7-a of GALL, Volume 2, in order to manage crack initiation and growth/primary water SCC in nickel-based BMI nozzles, the staff recommends that applicants for license renewal are either to provide a plant-specific AMP for managing these aging effects, or to indicate that they are participating in industry programs to determine the appropriate AMPs for managing these aging effects in the BMI nozzles.

The applicant's AMR for the BMI nozzles is different from the recommendations in AMR Item IV.A2.7-a of GALL, Volume 2, because the applicant is proposing to use an existing inspection program, that is the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program, to manage PWSCC in the RNP BMI nozzles in lieu of a plant-specific, inspection-based program developed by the applicant or by the industry. The RNP BMI nozzles are fabricated from Alloy 600 materials and are joined to the low-alloy steel lower RV head using Alloy 82/182 weld metals. As discussed in Section 3.1.2.3.6.2 of this SER, industry experience has demonstrated that Alloy 600 base metals and Alloy 82/182 weld materials may be susceptible to PWSCC.

The current ASME Section XI inspection requirements for BMI nozzles invoke visual VT-2 examinations of the components for leakage once every refueling outage. Recently, the licensee for the South Texas Project (STP) reported cracking in two welds that connect the BMI nozzles to the reactor vessel. To address the generic implications of the STP experience on the industry, the NRC issued Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity (August 21, 2003)," to all license holders (henceforth the addressees) of PWRs in the United States. In the bulletin, the staff asked the addressees to describe the plant-specific programs for inspecting the BMI nozzles at their facilities during the next and subsequent refueling outages. The staff also requested that the description include discussions on the extent of the inspections that would be conducted with respect to the areas and penetrations to be inspected, the inspection methods that would be used, the qualification standards that would be used for the inspection methods, the process that would be used to resolve the source of findings of boric acid deposits or corrosion, the inspection documentation that would be generated as a result of the examinations, and the basis for concluding that the facilities would continue to satisfy applicable regulatory requirements related to the structural and leakage integrity of the BMI nozzles or other lower reactor vessel head penetration nozzles.

The applicant submitted its response to NRC Bulletin 2003-02 by letter dated November 13, 2003 (refer to Progress Energy Serial Letter No. RNP-RA/03-0139). The staff is currently reviewing the industry's responses to Bulletin 2003-02 (including the response to the bulletin provided by the applicant in its November 13, 2003, letter to the NRC Document Control Desk) to assess the acceptability of current licensee lower vessel head inspection programs to identify BMI nozzle leakage, and to determine the need for, and guide the development of, any additional regulatory actions (e.g., generic communications, orders, or rulemaking) to address the integrity of the RCPB. Such regulatory actions could include regulatory requirements for augmented inspection programs under 10 CFR 50.55a(g)(6)(ii).

This current operating term issue raises questions about the capability of the BMI nozzles or other lower vessel head penetration nozzles to perform their intended functions during the current operating term. The Commission recognized that aging issues of this type could arise during the license renewal review and provided for such issues in 10 CFR 54.30, which requires that such issues be addressed under the current license, rather than as part the license renewal review. Therefore, pursuant to 10 CFR 54.30(b), this issue is beyond the scope of this license renewal review.

The STP experience, however, may call into question the ability of current code requirements to manage PWSCC-induced cracking in the RNP BMI nozzles or their structural welds. Therefore, in RAI 3.1.2.4.4-1, the staff asked the applicant to provide a basis as to why the applicant considers the required ASME VT-2 examinations to be adequate for managing PWSCC in the RV bottom head instrumentation tube nozzle welds at RNP.

The applicant provided the following response to RAI 3.1.2.4.4-1, dated April 28, 2003:

> RNP is participating in industry-wide programs for nickel-based alloy penetrations. For example, in LRA Table 3.1-1, Item 23, RNP has proposed managing reactor vessel nozzles of the same material using a combination of the Nickel-Alloy Nozzles and Penetrations Program and Water Chemistry Program. The Nickel-Alloy Nozzles and Penetrations Program is a new program, which is described in Section B4.1 of the LRA. Subsection A.3.1.28, Nickel-Alloy Nozzles and Penetrations Program, of the LRA states the following:
>
> > Prior to the period of extended operation, the Nickel-Alloy Nozzles and Penetrations Program will incorporate the following: (1) CP&L will perform evaluation of indications under the ASME Section XI program, (2) CP&L will perform corrective actions for augmented inspections to repair and replacement procedures equivalent to those requirements in ASME Section XI, (3) CP&L will maintain its involvement in industry initiatives (such as the Westinghouse Owners Group and the EPRI Materials Reliability Project) during the period of extended operation.
>
> For additional information conceming the Nickel-Alloy Nozzles and Penetrations Program, please refer to the RNP Response to RAI B4.1 -1.

The applicant's response to RAI 3.1.2.4.4-1 indicates that, although the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program is being credited with managing PWSCC in the RNP bottom head instrumentation tube nozzles, the applicant is relying on the commitments for its Nickel-Alloy Nozzles and Penetrations Program and continued participation in the industry's initiatives for evaluating the aging of nickel-based alloy components. As a result of this response, the staff believes the applicant should credit the Nickel-Alloy Nozzles and Penetrations Program as an additional AMP for the components within the scope of AMR Item 10 of LRA Table 3.1-2. The staff requested that CP&L confirm that it is crediting the Nickel-Alloy Nozzles and Penetrations Program as an additional AMP for managing PWSCC in the RNP bottom head instrumentation tube nozzles. This is Confirmatory Item 3.1.2.4.4.3-1.

The applicant provided the following response to Confirmatory Item 3.1.2.4.4.3-1 by letter dated September 16, 2003:

> In the response to RAI Clarification G, RNP amended part (3) of the commitment associated with the Nickel-Alloy Nozzles and Penetrations Program to the following:
>
> > *"(3) RNP will maintain its involvement in industry initiatives and will implement any actions, unless impracticable, that are agreed upon between the NRC and the nuclear power industry to monitor for, detect, evaluate, and correct cracking in the VHP nozzles, specifically as the actions relate to ensuring the integrity of VHP nozzles in the RNP upper reactor vessel head during the extended period of operation."*
>
> RNP will add items detailed in Table 3.1-2, AMR Item 10, to the program if required by the results of the commitment stated above. Also, note that in the response to RAI Clarification G, RNP also agreed to submit, for review and approval, its inspection plan for the Nickel-Alloy Nozzles and Penetrations Program, as it will be implemented from participation in industry initiatives prior to

July 31, 2009.

The staff's assessment of the Nickel-Alloy Nozzles and Penetrations Program (Section 3.1.2.3.6.2 of this SER) indicates that the RNP RV bottom head instrumentation tube nozzles are within the scope of the AMP. The applicant's response to Confirmatory Item 3.1.2.4.4.3-1 indicates that the applicant will use its commitment to determine whether augmented inspections of the bottom mounted instrumentation nozzles to the RV need to be added to the scope of the Nickel-Alloy Nozzles and Penetrations Program.

This commitment, which is also discussed in the applicant's response to RAI B.4.1-1 and specified in the latest version of Commitment No. 31 to Attachment II of CP&L Serial Letter No. RNP-RA/03-0031, dated April 28, 2003, includes a commitment to submit the inspection for the Nickel-Alloy Nozzles and Penetrations Program to the staff by July 31, 2009, for review and approval. The staff's review of the inspection plan for the Nickel-Alloy Nozzles and Penetrations Program, when submitted to the staff in conformance with the commitment, will provide the staff an opportunity to resolve with the applicant which inspection methods are appropriate for the RNP RV bottom head instrumentation tube nozzles and whether the existing ASME ISI methods for the nozzles need to be augmented.

Based on the applicant's commitment in Commitment No. 31 to Attachment II of CP&L Serial Letter No. RNP-RA/03-0031, and the clarification provided in the applicant's responses to RAIs 3.1.2.4.4-1 and B.4.1-1 and to Confirmatory Item 3.1.2.4.4.3-1, the staff concludes that the applicant has provided an acceptable method of determining which inspection methods will be necessary for the RNP bottom head instrumentation tube nozzles during the extended period of operation for RNP, as determined from the industry's initiatives on managing degradation of nickel-based alloy components and welds, the state of pertinent industry OE on degradation of PWR bottom head instrumentation tube nozzles (including that for STP), and the staff's resolution of this OE with licensed utilities in the industry. Confirmatory Item 3.1.2.4.4.3-1 is resolved.

The applicant's ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program is described in Section B.2.1 of Appendix B of the LRA. The staff evaluates the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program in Section 3.0.3.2 of this SER.

Based on this assessment, the staff concludes that the applicant's AMR analysis in Item 10 of LRA Table 3.1-2 provides an acceptable alternative to the corresponding AMR in commodity group item Section IV.A2.7-a of GALL, Volume 2.

Conclusions

AMR Item 10 to LRA Table 3.1-2 is an alternative AMR to corresponding AMRs discussed in the GALL Report for management of aging effects for the RNP RV bottom head instrumentation tube nozzles under exposure to borated treated water. On the basis of the staff's review and the applicant's commitment in Commitment No. 31 to Attachment II of CP&L Serial Letter No. RNP-RA/03-0031 (dated April 28, 2003), the staff concludes that the applicant has demonstrated that the aging effects for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.1.2.4.5 Reactor Vessel Internals

Table 3.1-2 of the LRA provides AMRs for RCS components that the applicant has determined are not covered by the scope of corresponding AMR items in GALL, Volume 2, or are not consistent with the scope of corresponding AMR items in GALL, Volume 2. The following AMRs in Table 3.1-2 of the LRA include the additional AMRs for RNP RV internal components:

- AMR Item 2 in which the applicant evaluates loss of material due to crevice or pitting corrosion in austenitic SS or nickel-based alloy reactor coolant system components that are exposed internally to treated water or steam
- AMR Item 9 in which the applicant evaluates cracking due to stress-corrosion cracking in the reactor vessel core support pads that are fabricated from nickel-based alloy and are exposed to the treated borated water in the primary coolant
- AMR Item 14 in which the applicant evaluates reduction of fracture toughness due to thermal embrittlement and neutron irradiation embrittlement in reactor vessel internal components fabricated from CASS
- AMR Item 15 in which the applicant evaluates loss of preload due to stress relaxation in RV internal bolts and springs other than baffle/former bolts
- AMR Item 16 in which the applicant evaluates cracking due to stress corrosion cracking in the reactor vessel internal flux thimble tubes fabricated from nickel-based alloy

3.1.2.4.5.1 Crevice or Pitting Corrosion in Stainless Steel or Nickel-Based RCS Components Under Internal Treated Water Environments—Evaluation of AMR Item 2 of LRA Table 3.1-2

In AMR Item 2 of Table 3.1-2 of the LRA, the applicant identified that loss of material due to crevice or pitting corrosion is an applicable aging effect for a number of RCS components that are fabricated from SS or nickel-based alloys and are exposed to treated water environments. These components include core support pads, flux thimbles, and guide tubes. The staff's evaluation of AMR Item 2 of LRA Table 3.1-2 is provided in SER Section 3.1.2.4.1.1.

3.1.2.4.5.2 Cracking Due to SCC in RV Core Support Pads—Evaluation of AMR Item 9 in LRA Table 3.1-2

<u>Summary of Technical Information in the Application</u>

The applicant provided its AMR for cracking due to SCC of the nickel-based alloy RV core supports pads under exposure to borated treated water or steam environments in AMR Item 9 of Table 3.1-2 of the LRA.

<u>Evaluation—Identification of Aging Effects</u>

The applicant identified that cracking due to SCC is the applicable aging effect for the core support pads under these environments and credited the Chemistry Control Program with managing this effect in the RV core support pads. In AMR Item IV.A2.6-a of GALL, Volume 2, the staff identifies that crack initiation and growth due to PWSCC (a form of SCC that is applicable under primary treated water environments) is an applicable aging effects for Alloy 600 core support pads/core guide lugs and states that either a plant-specific AMP is to be proposed to manage these effects, or an applicant is to indicate that it will participate in industry-wide programs that will evaluate and determine the appropriate type of AMPs that will be used to manage crack initiation and growth in these components. Industry experience has demonstrated that PWSCC can occur in nickel-based alloy components and welds in spite of controlled maintenance of reactor coolant chemistry. The staff concurs with the applicant that SCC is an applicable aging effect for the RNP RV core support pads that are exposed internally to the chemically treated borated water environment. The staff concludes that AMR Item 9 of LRA Table 3.1-2 is acceptable with respect to the aging effects discussed in the AMR.

<u>Evaluation—Aging Management Programs</u>

The applicant credits the Water Chemistry Program with managing crack initiation and growth from PWSCC in the Alloy 600 core support pads. The applicant describes and discusses the Water Chemistry Program in Section B.2.2 of Appendix B of the LRA. The staff evaluates the Water Chemistry Program in Section 3.0.3 of this SER.

The staff is concerned that chemistry control programs by themselves may not be capable of managing PWSCC-induced crack initiation and growth in the Alloy 600 components (including the core support pads) since PWSCC may occur in these components even when the impurity levels of reactor coolant have been maintained within the recommended limits cited in industry standards or guidelines. Therefore, in RAI 3.1.2.4.5-1, the staff requested that the applicant propose an inspection-based program that will be used in conjunction with the Water Chemistry Program to manage PWSCC-induced crack initiation and growth in the RNP Alloy 600 core support pads during the period of extended operation.

The applicant provided the following response to RAI 3.1.2.4.5-1 by letter dated April 28, 2003:

> RNP will remain active in industry groups (e.g., see the RNP Response to RAI 3.1.2.4.4-1) to stay aware of new industry recommendations regarding inspections of core support pads. New developments and recommendations in this area will be reviewed for applicability to RNP, and will add or modify AMPs, as appropriate. This action will be in addition to the existing reliance on the Water Chemistry Program.

The applicant's response states that the applicant will remain active in the industry's activities to stay aware of new industry recommendations regarding inspections for core support pads. The applicant refers to the information in its response to RAI 3.1.2.4.4-1 as providing additional detailed information on how this participation will be used to determine the necessary course of action for the core support pads. When taken in context with the applicant's response to RAI 3.1.2.4.4-1, the response to RAI 3.1.2.4.5-1 implies that the applicant will use its participation in the industry's activities on nickel-based alloy components to determine whether the Nickel-Alloy Nozzles and Penetrations Program needs to be augmented to include proposed inspections for the RNP core support pads. The staff seeks confirmation that CP&L is crediting the Nickel-Alloy Nozzles and Penetrations Program as an additional AMP for managing PWSCC in the RV core support pads. This is Confirmatory Item 3.1.2.4.5.2-1. The staff's assessment of the Nickel-Alloy Nozzles and Penetrations Program is given in Section 3.1.2.3.6.2 of this SER.

The applicant provided the following response to Confirmatory Item 3.1.2.4.5.2-1 by letter dated

September 16, 2003:

In the response to RAI Clarification G, RNP amended part (3) of the commitment associated with the Nickel-Alloy Nozzles and Penetrations Program to the following:

> *"(3) RNP will maintain its involvement in industry initiatives and will implement any actions, unless impracticable, that are agreed upon between the NRC and the nuclear power industry to monitor for, detect, evaluate, and correct cracking in the VHP nozzles, specifically as the actions relate to ensuring the integrity of VHP nozzles in the RNP upper reactor vessel head during the extended period of operation."*

RNP will add items detailed in Table 3.1-2, AMR Item 9, to the program if required by the results of the commitment stated above. Also, note that in the response to RAI Clarification G, RNP also agreed to submit, for review and approval, its inspection plan for the Nickel-Alloy Nozzles and Penetrations Program, as it will be implemented from participation in industry initiatives prior to July 31, 2009.

The applicant's response to Confirmatory Item 3.1.2.4.5.2-1 indicates that the applicant will use its commitment to determine whether augmented inspections of the core support pads need to be added to the scope of the Nickel-Alloy Nozzles and Penetrations Program. This commitment, which is also discussed in the applicant's response to RAI B.4.1-1 and specified in the latest version of Commitment No. 31 to Attachment II of CP&L Serial Letter No. RNP-RA/03-0031, dated April 28, 2003, includes a commitment to submit the inspection plan for the Nickel-Alloy Nozzles and Penetrations Program to the staff by July 31, 2009, for review and approval. The staff's review of the inspection plan for the Nickel-Alloy Nozzles and Penetrations Program, when submitted to the staff in conformance with the commitment, will permit the staff sufficient opportunity to resolve with the applicant which inspection methods are appropriate for the RNP RV core support pads and whether the Nickel-Alloy Nozzles and Penetrations Program needs to be augmented to include these components.

Based on the applicant's commitment in Commitment No. 31 to Attachment II of CP&L Serial Letter No. RNP-RA/03-0031, and the clarification provided in the applicant's responses to RAIs 3.1.2.4.4-1 and B.4.1-1 and to Confirmatory Item 3.1.2.4.5.2-1, the staff concludes that the applicant has provided an acceptable method of determining which inspection methods will be necessary, if any, for the RNP RV core support pads during the extended period of operation for RNP, as determined from the applicant's commitment to maintain its continued participation in the industry's initiatives on nickel-based alloy components and welds as well as its commitment to submit the Nickel-Alloy Nozzles and Penetrations Program to the staff for review and approval. Confirmatory Item 3.1.2.4.5.2-1 is resolved.

Based on this assessment, the staff concludes that the applicant's AMR analysis in Item 9 of Table 3.1-2 of the LRA provides an acceptable alternative to the corresponding AMR in commodity group item IV.A2.6-a of GALL, Volume 2, and RAI 3.1.2.4.4-1 is resolved.

<u>Conclusions</u>

AMR Item 10 of LRA Table 3.1-2 is an alternative AMR to corresponding AMRs discussed in the GALL Report for management of aging effects for the RNP RV core support pads under exposure to borated treated water. On the basis of its review and the applicant's commitment in Commitment No. 31 to Attachment II of CP&L Serial Letter No. RNP-RA/03-0031 (dated April 28, 2003), the staff concludes that the applicant has demonstrated that the aging effects for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.1.2.4.5.3 Reduction of Fraction Toughness Due to Thermal Embrittlement and Neutron Irradiation Embrittlement in CASS RV Internals—Evaluation of AMR Item 14 to LRA Table 3.1-2

Summary of Technical Information in the Application

The applicant provided its alternative AMR for age-related degradation in RV internal components fabricated from CASS in AMR Item 14 of Table 3.1-2 of the LRA.

Evaluation—Identification of Aging Effects

In AMR 14 of Table 3.1-2 of the LRA, the applicant identified that loss of fracture toughness due to thermal aging and neutron irradiation embrittlement is an aging effect for the RV internals that are fabricated from CASS and are exposed to the treated water in the borated reactor coolant. The corresponding AMR commodity group items in GALL, Volume 2, for evaluation of these aging effects in CASS RV internals are AMR Items IV.B2.1-g, upper internal assembly (which includes GALL component B.2.1.2, upper support column), and IV.B2.5-m, lower internal assembly (which includes GALL components IV.B2.5.3, lower support forging or casting, and IV.B2.5.4, lower support plate columns).

According to the license renewal issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components," dated May 2000,[9] certain CASS components are known to be particularly susceptible to reduction in fracture toughness as a result of thermal aging; neutron embrittlement of CASS internals may enhance this effect. The applicant's identification that loss of fracture toughness due to thermal aging and neutron irradiation embrittlement is an aging effect for the RV internals that are fabricated from CASS and are exposed to the treated water in the borated reactor coolant is consistent with staff's identification of aging effects in AMR commodity group items IV.B2.1-g and IV.B2.5-m, and is therefore acceptable to the staff.

Evaluation—Aging Management Programs

Inspections for RV internal components must use a method that is capable of detecting flaws that may exist in the components prior to growth of that flaw to a size that is larger than the critical crack size for the components. The applicant proposed to use the PWR Vessel Internals Program as its basis for managing loss of fracture toughness due to thermal aging and neutron irradiation embrittlement in the CASS RV internals at RNP. In contrast, GALL, Volume 2, recommends that applicants owning Westinghouse-designed PWRs implement GALL XI.M12, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel," to manage loss of fracture toughness due to thermal aging and neutron irradiation embrittlement in the CASS RV internal components within the scope of GALL AMR Items IV.B2.1-g and IV.B2.5-m, including Westinghouse-designed RV internal upper support

[9]Letter from Mr. C. I. Grimes (NRC) to D.J. Walters (NEI), *License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components,"* Project No. 690, dated May 2000.

columns, lower support forging/castings, and lower support columns made from CASS. The applicant's description of the PWR Vessel Internals Program is given in Section B.4.3 of Appendix B of the RNP LRA.

The staff's evaluation of the applicant's PWR Vessel Internals Program is given in Section 3.1.2.3.4 of this SER. The evaluation in Section 3.1.2.3.4 includes RAI B.4.3-1 that, in part, addresses the issue of the ability of the PWR Vessel Internals Program to manage loss of fracture toughness in the RV internals fabricated from CASS. The staff's resolution of RAI B.4.3-1 is also applicable to the staff's evaluation of AMR Item 14 of LRA Table 3.1-2, as related to the ability of the PWR Vessel Internals Program to manage loss of fracture toughness due to thermal aging and neutron irradiation embrittlement in the RNP RV internals fabricated from CASS. The staff's assessment in Section 3.1.2.3.4 of this SER also discusses the applicant's commitments relative to the implementation of the PWR Vessel Internals Program, including the commitment to submit the inspection plan to the staff for review and approval 24 months prior to implementation. The applicant's commitments for the PWR Vessel Internals Program are given in Commitment No. 33 of Attachment II to CP&L Serial Letter No. RNP-RA/03-0031.

Based on the staff's assessment of the PWR Vessel Internals Program, the staff's resolution of RAI B.4.3.-1, and the applicant's commitment to submit the inspection plan for the PWR Vessel Internals Program to the staff for review and approval, as discussed in Section 3.1.2.3.4 of this SER, the staff concludes that the AMR in Item 14 of LRA Table 3.1-2 is an acceptable alternative to the AMPs recommended in commodity group items IV.B2.1-g (upper internal assembly which includes GALL component B.2.1.2, upper support column, portions made from CASS) and IV.B2.5-m (lower internal assembly which includes GALL components IV.B2.5.3, lower support forging or casting, and IV.B2.5.4, lower support plate columns) for managing loss of fracture toughness in the CASS RV internals. Based on this assessment, the staff concludes that AMR Item 14 of LRA Table 3.1-2 is acceptable, and RAI 3.1.2.4.5-1 is resolved.

Conclusions

AMR Item 14 to LRA Table 3.1-2 is an alternative AMR to corresponding AMRs discussed in the GALL Report for management of aging effects for the CASS RNP RV internal components under exposure to borated treated water. On the basis of this review and the applicant's commitment in Commitment No. 33 to Attachment II of CP&L Serial Letter No. RNP-RA/03-0031 (dated April 28, 2003), the staff concludes that the applicant has demonstrated that the aging effects for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.1.2.4.5.4 Loss of Preload Due to Stress Relaxation in RV Internal Upper Support Column Bolts, Holddown Springs, Lower Support Plate Column Bolts and Clevis Insert Bolts—Evaluation of AMR Item 15 to LRA Table 3.1-2

Summary of Technical Information in the Application

The applicant provides its alternative AMR for loss of preload in the RV internal upper support column bolts, holddown springs, lower support plate column bolts, and clevis insert bolts in AMR Item 15 of Table 3.1-2 of the LRA.

Evaluation—Identification of Aging Effects

In AMR 15 of Table 3.1-2 of the LRA, the applicant identified that loss of preload due to stress relaxation is an applicable aging effect for the RV internal upper support column bolts, holddown springs, lower support plate column bolts, and clevis insert bolts and stated that this aging effect requires management during the extended period of operation for RNP. The corresponding AMR commodity group items in GALL, Volume 2, for evaluating loss of preload in these RV internals components are AMR commodity group items IV.B2.1-k (upper internal assembly, which includes GALL component B.2.1.3, upper support column bolts); IV.B2.1-d (upper internal assembly, which includes GALL component B.2.1.7, holddown spring); IV.B2.5-h (lower internal assembly, which includes GALL component IV.B2.5.5, lower support plate column bolts); and IV.B2.5-i (lower internal assembly, which includes GALL component IV.B2.5.7, clevis insert bolts). The applicant's identification that loss of preload is an applicable aging effect for the RNP RV internal upper support column bolts, holddown springs, lower support plate column bolts, and clevis insert bolts is consistent with AMRs provided in AMR commodity groups IV.B2.1-k, IV.B2.1-d, IV.B2.5-h, and IV.B2.5-i of GALL, Volume 2, for these components, and is therefore acceptable to the staff.

Evaluation—Aging Management Programs

GALL, Volume 2, recommends that GALL XI.M1, "ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD," for Class 1 components be used in conjunction with GALL XI.M14, "Loose Parts Monitoring," to manage loss of preload in the upper support column bolts and in the lower support column bolts. GALL, Volume 2, recommends that GALL XI.M1, "ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD," for Class 1 components be used in conjunction with either GALL XI.M14, "Loose Parts Monitoring," or GALL XI.M15, "Neutron Noise Monitoring," to manage loss of preload in the holddown springs and clevis insert bolts.

In AMR Item 15 of LRA Table 3.1-2, the applicant credited the ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program and PWR Vessel Internals Program as the two AMPs with managing loss of preload in the RNP RV internal upper support column bolts, holddown springs, lower support plate column bolts, and clevis insert bolts. This deviates from the AMPs recommended in GALL, Volume 2, for managing loss of preload in these components. In its discussion of this AMR (i.e., in column 6 of AMR Item 15 of LRA Table 3.1-2), the applicant provided the following technical justification for crediting the PWR Vessel Internals Program to manage this aging effect in lieu of using the Loose Part Monitoring Program or Neutron Noise Monitoring Program.

> The GALL Report cites (1) a combination of ASME Section XI, Inservice Inspection and loose parts and/or neutron noise monitoring programs for the holddown spring and clevis insert bolts, and (2) a combination of ASME Section XI, Inservice Inspection, and loose parts monitoring for upper support column bolts and lower support plate column bolts. RNP employs both the ASME Section XI, Subsections IWB, IWC, and IWD Program and the PWR Vessel Internals Program to address stress relaxation for these components. RNP considers the recommendations regarding neutron or noise monitoring to be ineffective to the management of aging effects. By the time neutron or noise monitoring indicate a concern, the aging degradation would have reached an unacceptable condition. As discussed previously, RNP will incorporate the applicable results of industry initiatives related to aging effects for reactor vessel internals into the PWR Vessel Internals Program. This includes information on loss of preload due to stress relaxation. The AMPs used at RNP will effectively manage the effects of loss of preload for affected internals components.

The applicant describes and discusses the PWR Vessel Internals Program in Section B.4.3 of Appendix B of the RNP LRA. The staff's evaluation of the applicant's PWR Vessel Internals Program is given in Section 3.1.2.3.8 of this SER. The evaluation in Section 3.1.2.3.8 includes RAI B.4.3-1 that, in part, addresses the issue of the ability of the PWR Vessel Internals Program to manage loss of preload in the RV internal bolted connections, holddown springs, and clevis inserts. RAI B.4.3-1 is also applicable to the staff's evaluation of AMR Item 15 of LRA Table 3.1-2, as it relates to the ability of the PWR Vessel Internals Program to manage loss of preload in the RNP RV internal upper support column bolts, holddown springs, lower support plate column bolts, and clevis insert bolts. The staff's assessment in Section 3.1.2.3.4 of this SER also discusses the applicant's commitments relative to the implementation of the PWR Vessel Internals Program, including the commitment to submit the inspection plan for the AMP to the staff for review and approval 24 months prior to implementation. The applicant's commitments for the PWR Vessel Internals Program are given in Commitment No. 33 of Attachment II to CP&L Serial Letter No. RNP-RA/03-0031, dated April 28, 2003.

Conclusions

AMR Item 15 of LRA Table 3.1-2 is an alternative AMR to corresponding AMRs discussed in the GALL Report for managing loss of preload due to stress relaxation in the RV internal upper support column bolts, holddown springs, lower support plate column bolts, and clevis insert bolts and states that this aging effect requires management during the extended period of operation for RNP under exposure to borated treated water. On the basis of this review and the applicant's commitment in Commitment No. 33 to Attachment II of CP&L Serial Letter No. RNP-RA/03-0031 (dated April 28, 2003), the staff concludes that the applicant has demonstrated that loss of preload in these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.1.2.4.5.5 Cracking Due to SCC in RV Incore Flux Thimbles Fabricated from Nickel-Based Alloy—Evaluation of AMR Item 16 to LRA Table 3.1-2

Summary of Technical Information in the Application

The applicant provided its alternative AMR for evaluating crack initiation and growth in the RNP RV incore flux thimble tubes in AMR Item 16 of Table 3.1-2 to the LRA.

Evaluation—Identification of Aging Effects

In AMR Item 16 of Table 3.1-2 to the LRA, the applicant stated that the RV incore flux thimbles are fabricated from nickel-based alloy and are exposed to the treated water environment of the borated reactor coolant. The applicant identified that SCC is an applicable aging effect for these components and requires management during the extended period of operation for RNP.

Industry experience has demonstrated that nickel-based alloys which are exposed to reactor coolant are susceptible to the initiation of PWSCC, which is a form of SCC that may occur even in the presence of high-quality, chemically-treated, borated water (refer to Section 3.1.2.3.6 of this SER). Section IV.B2 of GALL, Volume 2, does not include a corresponding AMR analysis that identifies that cracking due to SCC is an applicable aging effect for Westinghouse incore flux thimbles that are fabricated from nickel-based alloys and are exposed to borated water environments. The applicant has identified that cracking due to SCC is an applicable aging effect for the nickel-based alloy incore flux thimbles at RNP. This is consistent with current industry experience on PWSCC of nickel-based alloy components and is acceptable.

Evaluation—Aging Management Programs

In AMR Item 16 of LRA Table 3.1-2, the applicant credited only the Chemistry Control Program with managing SCC in the RNP RV neutron flux thimbles. The staff is concerned that water chemistry programs alone may not be sufficient to prevent cracking in internal surfaces of nickel-based alloy components of the reactor coolant pressure boundary since PWSCC may occur in these components even when the impurity concentrations for oxygen and aggressive anions in the borated reactor coolant are controlled to acceptable levels. Therefore, in RAI 3.1.2.4.5-2, the staff asked the applicant to provide a technical basis as to why the applicant considered the Water Chemistry Program sufficient to manage PWSCC-induced cracking in these components without the need for confirmation using an inspection-based AMP.

The applicant provided the following response to RAI 3.1.2.4.5-2 by letter dated April 28, 2003:

> The RNP flux thimble guide tubes are fabricated from stainless steel. The flux thimble guide tubes, equivalent to GALL Item IV.B2.6.1 in Volume 2 (GALL Items IV.B2.6-a and IV.B2.6-b), are part of the group of components evaluated in LRA Table 3.1-1, Item 33. This AMR item manages cracking due to various forms of SCC with the Water Chemistry Program and the PWR Vessel Internals Program. Therefore, RNP is consistent with GALL. LRA Table 3.1-2, Item 16, is used for the evaluation of the Reactor Vessel Internals Flux Thimble [Tubes]. This item is equivalent to GALL Item IV.B2.6.2 in Volume 2 (GALL Item IV.B2.6-c).

The applicant's response to the RAI did not provide sufficient clarification whether the components within the scope of AMR 16 in LRA Table 3.1-2 were the incore flux thimbles or the incore flux thimble tubes that house the thimbles. The staff asked for confirmation whether the scope of AMR 16 to LRA Table 3.1-2 was on the incore flux thimbles or the incore flux thimble tubes, and designated this request as confirmatory Item 3.1.2.4.5.5-1.

The applicant provided the following response to Confirmatory Item 3.1.2.4.5.5-1 by letter dated December 10, 2003:

> The scope of Aging Management Review (AMR) 16 of license renewal application (LRA) Table 3.1-2 evaluates cracking due to stress corrosion cracking (SCC) for the retractable incore flux thimble tubes fabricated from nickel-based alloy (Alloy 600), and not for the fixed guide tube that is welded to the reactor vessel and attached to the seal table. AMR 33 of LRA Table 3.1-1 evaluates cracking due to SCC for the guide tube which is made from Type 304 stainless steel. For the guide tube, an inspection based program (PWR Vessel Internals Program) is used in conjunction with the Water Chemistry Program to manage cracking due to SCC.
>
> The RNP flux thimble tubes are a double wall design consisting of an Alloy 600 outer sheath and Alloy 600 calibration tube with thermocouple leads between the two. The normal environment for the outer sheath is treated water on the outside surface and air on the inside surface. The outer sheath provides a barrier between the treated water and the calibration tube so the normal environment for the calibration tube is air for both the inner and outer surfaces. AMR 16 of LRA Table 3.1-2 evaluates cracking due to SCC for the retractable Alloy 600 flux thimble tubes. This is applicable to the outer sheath. The Water Chemistry Program is credited for managing this aging effect. It should be noted that periodic sampling for contaminants assures that corrosion processes

are not occurring. This sampling provides verification of the effectiveness of water chemistry control. In addition, the Nickel-Alloy Nozzles and Penetrations Program is credited for management of Alloy 600 cracking. The calibration tube is subject to wear, but is not subject to SCC due to the normal environment of air for both the inner and outer surfaces. AMR 28 of Table 3.1-1 evaluates wear of this inner calibration tube by periodic eddy current testing.

The applicant's response to Confirmatory Item 3.1.2.4.5.5-1 provides clarification that the design of the incore flux thimble guide tubes and incore flux thimbles is different from the designs at most other Westinghouse-designed PWRs in the U.S. The incore flux thimble guide tube (called conduit tubes at Robinson) is welded to the reactor vessel instrument penetration and connected to the seal table. The conduit tubes, which are fabricated A213 TP304 stainless steel (cold drawn and heat treated), are exposed externally to containment air and internally to the reactor coolant. The staff's evaluation of the aging effects for the conduit tubes is given in the staff's evaluation of LRA Table 3.1-1, AMR Item 33, which is provided in SER Section 3.1.2.1.

The RNP flux thimbles are of a double-wall (double-tube) design configuration. The outmost tubes of the thimbles are outer sheaths that are fabricated from Alloy 600. The outer sheaths are exposed externally to the reactor coolant and internally to containment air. The innermost tubes of the thimbles (which are also called the calibration tubes at RNP) are contained within the outer sheaths. The calibration tubes are also fabricated from Alloy 600 and exposed both internally and externally only to containment air. The thimble tubes also contain two thermocouple leads, which are periodically replaced by the applicant, and are therefore not subject to aging management reviews.

The applicant has credited both the Water Chemistry Program and the Nickel-Alloy Nozzles and Penetrations Program with aging management of cracking Alloy 600 components in the Alloy 600 outer sheaths. This provides both a mitigative strategy and inspection-based strategy for managing cracking that may potentially occur in the outer sheaths as a result of exposure to the reactor coolant. The applicant's application includes Commitment No. 31 on the Nickel-Alloy Nozzles and Penetrations Program, which was updated in a NRC-approved version in CP&L Serial Letter No. RNP-RA/03-0154, dated December 10, 2003. This version of the commitment includes a commitment to: (1) participate in the MRP's industry initiatives on cracking of nickel-based alloy components, (2) implement those recommendations that result for the MRP's studies on these matters and are acceptable to the NRC, and (3) to submit the inspection plan for the Nickel-Alloy Nozzles and Penetrations Program for NRC review and approval by July 31, 2009. The commitment to submit the Nickel-Alloy Nozzles and Penetrations Program for staff review and approval will provide a sufficient opportunity to determine whether cracking is an issue for the Alloy 600 thimble outer sheaths that are exposed to the reactor coolant and to discuss with the applicant whether inspections of the components will be needed during the extended period of operation for RNP. The staff therefore concludes that this is an acceptable process for managing cracking that may potentially occur in the thimble outer sheaths. Based on this assessment, the staff concludes that the applicant has proposed an acceptable basis for managing cracking in the flux thimbles at RNP and that AMR 16 of LRA Table 3.1-2 is acceptable.

Conclusions

The staff finds that the applicant has provided an acceptable basis for concluding that cracking due to SCC is an applicable aging effect requiring aging management for the RV incore flux thimble and for managing this aging effect during the extended period of operation for RNP. On the basis of this review, the staff concludes that the applicant has demonstrated that cracking due to SCC in the RV incore flux thimble tubes will be managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation for RNP.

3.1.2.4.6 Steam Generator

Table 3.1-2 of the LRA provides AMRs for RCS components that the applicant has determined are not covered by the scope of corresponding AMR items in GALL, Volume 2, or are not consistent with the scope of corresponding AMR items in GALL, Volume 2. The following AMRs in Table 3.1-2 of the LRA include the additional AMRs for RNP SG components:

- AMR Item 2 in which the applicant evaluates loss of material due to crevice or pitting corrosion in austenitic SS or nickel-based alloy reactor coolant system components[10] that are exposed internally to treated water or steam

- AMR Item 3 in which the applicant evaluates cracking due to stress corrosion cracking, loss of material due to crevice corrosion, and loss of material due to fretting in the RNP Steam Generator antivibration bars

- AMR Item 4 in which the applicant evaluates loss of material due to crevice or pitting corrosion and cracking due to stress corrosion cracking in steam generator secondary side components made from nickel-based alloys (i.e., in the feedwater nozzle thermal sleeve safeend and steam flow limiter)

- AMR Item 5 in which the applicant evaluates loss of material due to general corrosion, crevice corrosion, and/or pitting corrosion in steam generator secondary side components fabricated from carbon steel (i.e., in the feedwater nozzle thermal sleeve, secondary side manway and handhole covers, secondary side shell penetrations, tube bundle wrapper, and the tubeplate)

- AMR Item 6 in which the applicant evaluates loss of material due to erosion in steam generator secondary side components fabricated from either nickel-based alloy or carbon steel (i.e., in the steam generator tube bundle wrapper, tubeplate, and steam flow limiter)

- AMR Item 7 in which the applicant evaluates loss of material, cracking, and changes in material properties in steam generator snubber reservoir components

- AMR Item 11 in which the applicant evaluates cracking due to stress corrosion cracking in the steam generator lower head divider plate and steam generator tubeplate cladding that is fabricated from nickel-based alloy

- AMR Item 12 in which the applicant evaluates loss of mechanical closure integrity/loss of material resulting from aggressive chemical attack in steam generator secondary

[10] Refer to the list of components provided in footnote 8 of this section.

manway and handhole bolting made from carbon steel

3.1.2.4.6.1 Crevice or Pitting Corrosion in Stainless Steel or Nickel-Based RCS Components Under Internal Treated Water Environments—Evaluation of AMR Item 2 of LRA Table 3.1-2

In AMR Item 2 of Table 3.1-2 of the LRA, the applicant identifies that loss of material due to crevice or pitting corrosion is an applicable aging effect for a number of RCS components that are fabricated from SS or nickel-based alloys and are exposed to treated water environments. These components include the SG divider plate, SG primary manway inserts, and SG tubeplate cladding. The staff's evaluation of AMR Item 2 of LRA Table 3.1-2 is provided in SER Section 3.1.2.4.1.

3.1.2.4.6.2 Cracking Due to SCC, Loss of Material Due to Crevice Corrosion, and Loss of Material Due to Fretting in the RNP SG Antivibration Bars—Evaluation of AMR Item 3 of LRA Table 3.1-2

Summary of Technical Information in the Application

The applicant provides its AMR for the SG antivibration bars in AMR Item 3 of Table 3.1-2 of the LRA.

Evaluation—Identification of Aging Effects

In AMR Item 3 of Table 3.1-2 of the LRA, the applicant identifies that cracking due to SCC, and loss of material due to crevice corrosion and fretting, are applicable aging effects for the SG antivibration bars that are made from nickel-based alloy. The staff agrees with the applicant that cracking due to SCC and loss of material due to fretting are potential aging effects for the antivibration bars. Industry experience has shown that loss of material at antivibration bars is caused predominantly by fretting and wear (metal to metal contact).

In RAI 3.1.2.4.6-1, the staff referred the applicant to AMR Item 3 of LRA Table 3.1-2 (LRA page 3.1-32), where CP&L identified loss of material from crevice corrosion as an aging effect for the SG antivibration bars. Industry experience has shown that loss of material at antivibration bars are caused predominantly by fretting and wear (metal to metal contact) rather than by crevice corrosion. In the RAI, the staff requested the applicant to discuss why crevice corrosion was identified rather than fretting and wear for this item.

In its response to RAI 3.1.2.4.6-1, the applicant stated that the RNP LRA identified Loss of Material from Fretting" as an aging effect for the antivibration bars. The applicable aging effects identified for the antivibration bars are shown in Item 3 of LRA Table 3.1-2 and are as follows—cracking from SCC, loss of material from crevice corrosion, and loss of material from fretting. In determining whether or not an aging effect is applicable, RNP did not credit the beneficial effect of controlled water chemistry. This conservative assumption resulted in the identification of SCC and crevice corrosion as applicable aging mechanisms for the antivibration bars. The applicant referred to page 3.0-2 of the RNP LRA, which provides the following clarification on the applicant's aging management methodology:

> The aging management review methodology for RNP did not credit the effects of aging

> management programs when determining if an aging effect requiring management may be applicable. The potential aging effects were evaluated assuming that any applicable aging management programs were not in effect. No credit was taken for coatings and linings, cathodic protection systems, corrosion inhibitors, biocides, inspections or other programs during the aging management reviews, because the entire set of aging effects requiring management may not be identified if these programs were credited a priori.

The staff finds the applicant's response to RAI 3.1.2.4.6-1 acceptable because the applicant has clarified which aging effects (i.e., cracking from SCC, loss of material from crevice corrosion, and loss of material from fretting) are applicable for the SG antivibration bars and because the applicant conservatively considered the effects of aging that may, in fact, not be observed at RNP due to the success of the AMP credited for aging management. RAI 3.1.2.4.6-1 is resolved.

Evaluation—Aging Management Programs

The applicant identified the Steam Generator Tube Integrity Program and Water Chemistry Program to manage the aging effects of the antivibration bars. These are the programs that have been identified for the aging management of SG components as specified in Section IV.D1 of the GALL Report.

Conclusions

The applicant has provided its AMR for cracking from SCC, and loss of material due to crevice corrosion and fretting, as the aging effects for SG antivibration bars in AMR Item 3 of Table 3.1-2 of the LRA. The staff has reviewed the applicant's evaluation for AMR Item 3 of Table 3.1-2 and its response to the RAI. The staff has determined that the applicant's AMR for this item is acceptable and is consistent with the staff's AMRs for cracking from SCC and loss of material due to crevice corrosion and fretting in other SG components. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects for SG antivibration bars, as given in AMR Item 3 of Table 3.1-2 to the LRA, will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.1.2.4.6.3 Loss of Material Due to Crevice or Pitting Corrosion and Cracking Due to SCC in SG Secondary Side Components Made from Nickel-Based Alloys—Evaluation of AMR Item 4 of LRA Table 3.1-2

Summary of Technical Information in the Application

The applicant provides its AMR for the SG feedwater nozzle thermal sleeve safe end and steam flow limiter in AMR Item 4 of Table 3.1-2 of the LRA.

Evaluation—Identification of Aging Effects

In AMR Item 4 of LRA Table 3.1-2, the applicant identified cracking from SCC and loss of material from crevice or pitting corrosion as the aging effects for SG feedwater nozzle thermal sleeve safe ends and steam flow limiters that are made of nickel-based alloy in the treated water/steam environment. While GALL, Volume 2, does not have a corresponding AMR for cracking from SCC and loss of material from crevice or pitting corrosion in these secondaryside components, the AMR for commodity group item IV.D1.1-j states that cracking due to ODSCC, which is a form of SCC, is an applicable aging effect for SG tubes that are fabricated from nickel-based alloys and are exposed to the secondary side coolant; and the AMR for commodity group item IV.D1.2-f states that loss of material due to pitting corrosion is an applicable aging effect for SG tubes that are fabricated from nickel-based alloys and are exposed to the secondary side coolant. The staff finds the applicant's identification of aging effects for the SG feedwater nozzle thermal sleeve safe ends and steam flow limiters acceptable because they are made from nickel-based alloy and are exposed to the same secondary side coolant that the nickel-based alloy SG tubes are. Based on the staff's analysis of the aging effects for the materials and environments for the SG tubes in GALL commodity group items IV.D1.1-j and IV.D1.2-f, the staff finds the applicant's identification of aging effects in AMR Item 3 of LRA Table 3.1-2 to be acceptable.

Evaluation—Aging Management Programs

The applicant has credited the Water Chemistry Program with managing cracking due to SCC and loss of material from crevice or pitting corrosion in the SG feedwater nozzle thermal sleeve safe ends and steam flow limiters. The applicant stated that the Water Chemistry Program has been proven effective in managing SCC and pitting and crevice corrosion because it controls the aggressive chemical species that caused the aging mechanisms.

In AMR Item 4 of LRA Table 3.1-2 (LRA page 3.1-33), the applicant identified the Water Chemistry Program as the only AMP to manage the aging effect of SCC and loss of material due to pitting/crevice corrosion in the RNP SG feedwater nozzle thermal sleeve safe ends and steam flow limiters. In RAI 3.1.2.4.6-2, the staff asked whether the Water Chemistry Program is sufficient to manage loss of material and cracking in RCS components without the need for use of a confirmatory inspection-based AMP to verify that the Water Chemistry Program is achieving its preventive/mitigative purposes. Therefore, in the RAI, the staff asked the applicant for clarification and justification why the applicant considers that the Water Chemistry Program by itself will be sufficient to manage loss of material and cracking in the surfaces of the SG feedwater nozzle thermal sleeve safe ends and steam flow limiters, without the need for confirmation using an inspection-based program (such as the Steam Generator Tube Integrity Program or the Inservice Inspection Program) to verify that the Water Chemistry Program is achieving its preventive/mitigative purposes for managing loss of material and cracking in these components. The staff informed the applicant that RAI 3.1.2.4.6-2 is generic to the management of aging effects in the following SG components:

- loss of material due to general, pitting, and/or crevice corrosion in the steam generator feedwater nozzle thermal sleeves, secondary side manway and handhole covers, secondary side shell penetration nozzles, and steam generator tube bundle wrappers and tubeplates under exposure to treated water environments (AMR Item 5 of LRA Table 3.1-2)

- loss of material due to erosion in the steam generator tube bundle wrappers and steam generator tubeplates that are fabricated from carbon steel and the steam flow limiters that are made of nickel-based alloy under exposure to treated water environments (AMR Item 6 of LRA Table 3.1-2)

- cracking due to stress-corrosion cracking as the aging effect for steam generator lower head divider plates and tubeplate cladding that are fabricated of nickel-based alloy under treated water and steam environments (AMR Item 11 of LRA Table 3.1-2)

In its response to RAI 3.1.2.4.6-2, the applicant stated that the SG tubeplate is fabricated from carbon steel with a nickel-based alloy cladding. The applicable AMRs for the carbon steel tubeplate are discussed in LRA Table 3.1-1, Item 1 (cumulative fatigue damage, which is a TLAA evaluated item); LRA Table 3.1-2, Item 5 (loss of material from crevice, general or pitting corrosion managed by the Water Chemistry Program); and LRA Table 3.1-2, Item 6 (loss of material from erosion managed by the Water Chemistry Program).

LRA Table 3.1-2, Item 11, is an evaluation of the SG tubeplate cladding and SG lower head divider plate fabricated from nickel-based alloys in a treated water environment. The applicable aging effect is cracking from SG, which is managed by the Water Chemistry Program.

The SG lower head (GALL, Volume 2, Item IV.D1.1.8 (IV.D1.1-g)) is fabricated from carbon steel with SS cladding. The carbon steel head and its SS cladding are evaluated separately in the LRA. The carbon steel lower head is exposed to environments of containment air and borated water leakage. Since the lower head is internally clad, the carbon steel base material is not exposed to an environment of treated water. The applicable AMRs for the carbon steel lower head are LRA Table 3.1-1, Items 1 (cumulative fatigue damage) and 26 (loss of material due to boric acid corrosion which is managed by the Boric Acid Corrosion Program).

The SS cladding is exposed to an environment of treated water. The applicable AMRs for the lower head cladding are LRA Table 3.1-1, Items 1 and 32, and LRA Table 3.1-2, Item 2. LRA Table 3.1-1, Item 1, addresses cumulative fatigue damage, which is TLAA evaluated in accordance with 10 CFR 54.21(c). LRA Table 3.1-1, Item 32, addresses crack initiation and growth due to SCC, PWSCC, and IASCC which is managed by the ISI and the Water Chemistry Programs. LRA Table 3.1-2, Item 2, addresses loss of material from crevice or pitting corrosion, which is managed by the Water Chemistry Program.

The applicant stated that the adequacy of managing these aging effects by the use of the Water Chemistry Program has been previously accepted by the NRC and is consistent with industry practice. A discussion of the efficacy of the Water Chemistry Program to manage these aging effects is contained in the RNP response to RAI 3.4.1-10. In addition, the One-Time Inspection Program includes miscellaneous piping inspection to demonstrate water chemistry effectiveness for systems connected upstream of the SGs, such as the feedwater and AFW systems.

<u>Conclusions</u>

The applicant has provided its AMR for SCC and loss of material as the aging effects for SG components (feedwater nozzle thermal sleeve safe end and steam flow limiter) in AMR Item 4 of Table 3.1-2 of the LRA. The staff has reviewed the applicant's evaluation for AMR Item 4 of Table 3.1-2 and its response to RAI 3.1.2.4.6-2. The staff has determined that the applicant's AMR for this item is acceptable consistent with the staff's AMRs for SCC and loss of material in other SG components. On the basis of this review, the staff concludes that the applicant has demonstrated that the AMR for SCC and loss of material in the feedwater nozzle thermal sleeve safe end and steam flow limiter, as given in AMR Item 4 of Table 3.1-2 of the LRA, will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.1.2.4.6.4 Loss of Material Due to General Corrosion, Crevice Corrosion, and/or Pitting Corrosion in SG Secondary Side Components Fabricated from Carbon Steel—Evaluation of AMR Item 5 of LRA Table 3.1-2

Summary of Technical Information in the Application

The applicant provides its AMR for the SG components including SG feedwater nozzle thermal sleeves, secondary side manway and handhole covers, secondary side shell penetrations, SG tube bundle wrappers and tubeplates (tubesheet) in AMR Item 5 of Table 3.1-2 of the LRA.

Evaluation—Identification of Aging Effects

In AMR Item 5 of LRA Table 3.1-2, the applicant identified loss of material due to crevice, general, or pitting corrosion as the aging effects for SG components including the SG feedwater nozzle thermal sleeves, secondary side manway and handhole covers, secondary side shell penetrations, tube bundle wrappers and tubeplates that are made of carbon steel. These secondary components are not specified in the GALL Report. While GALL, Volume 2, does not have a corresponding AMR for loss of material due to general, crevice, or pitting corrosion in these secondary side components, the AMR for commodity group item IV.D1.1-c states that loss of material due to general, pitting, and crevice corrosion is an applicable aging effect for carbon steel upper and lower SG transition cones that are exposed to the secondary side coolant. The staff finds the applicant's identification of aging effects for the SG feedwater nozzle thermal sleeve safe ends and steam flow limiters is acceptable because they are made from carbon steel and are exposed to the same secondary side coolant that the carbon steel SG upper and lower transition cones are. Based on the staff's analysis of the aging effects for the materials and environments for the SG upper and lower transition cones, as described in GALL commodity group item IV.D1.1-c, the staff finds the applicant's identification of aging effects in AMR Item 5 of LRA Table 3.1-2 to be acceptable.

Evaluation—Aging Management Programs

The applicant credited the Water Chemistry Program with managing loss of material due to general, pitting, or crevice corrosion in the SG feedwater nozzle thermal sleeves, secondary side manway and handhole covers, secondary side shell penetrations, and SG tube bundle wrappers and tubeplates. The applicant stated that the Water Chemistry Program has been proven effective in managing SCC and pitting and crevice corrosion because it controls the aggressive chemical species that caused the aging mechanisms.

The general issue raised in Section 3.1.2.4.6.3 of this SER addresses the ability of water chemistry programs to manage loss of material and cracking in SG components without the need for confirmatory verification using inspection-based AMPs. Therefore, RAI 3.1.2.4.6-2 is also applicable to the management of loss of material due to general, crevice, and pitting corrosion in the SG components in LRA Table 3.1-2, Item 5, including feedwater nozzle thermal sleeves, secondary side manway and handhole covers, secondary side shell penetrations, tube bundle wrappers, and tubeplates.

Conclusions

The applicant has provided its AMR for loss of material due to general corrosion, crevice corrosion, and/or pitting corrosion as the aging effects for SG components, including feedwater nozzle thermal sleeves, secondary side manway and handhole covers, secondary side shell penetrations, tube bundle wrappers, and tubeplates in AMR Item 5 of Table 3.1-2 of the LRA. The staff has reviewed the applicant's evaluation for AMR Item 5 of Table 3.1-2 and its response to RAI 3.1.2.4.6-2. The staff has determined that the applicant's AMR for this item is acceptable consistent with the staff's AMRs for loss of material in other SG components. On the basis of this review, the staff concludes that the applicant has demonstrated that the AMR for loss of material in the SG components, as given in AMR Item 5 of Table 3.1-2 of the LRA, will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.1.2.4.6.5 Loss of Material Due to Erosion in SG Secondary Side Components Fabricated from Either Nickel-Based Alloy or Carbon Steel—Evaluation of AMR Item 6 of LRA Table 3.1-2

Summary of Technical Information in the Application

The applicant provides its AMR for the SG tube bundle wrapper, tubeplate (tubesheet), and steam flow limiter in AMR Item 6 of Table 3.1-2 of the LRA.

Evaluation—Identification of Aging Effects

In AMR Item 6 of LRA Table 3.1-2, the applicant identified loss of material due to erosion as the aging effect for SG components including the SG tube bundle wrappers, SG tubeplates that are fabricated from carbon steel, and the steam flow limiters that are made of nickel-based alloy under treated water environments. These secondary components are not specified in the GALL Report. While GALL, Volume 2, does not have a corresponding AMR for loss of material due to erosion in these secondaryside components, the AMR for commodity group item IV.D1.1-e states that loss of material due to erosion is an applicable aging effect for the feedwater impingement plates and supports that are made from carbon steel and are exposed to the secondary side coolant. While nickel-based alloys are normally designed to be resistant to the effects of erosion, the applicant has conservatively identified loss of material due to erosion as an applicable aging effect for the steam flow limiters that are made from nickel-based alloy and are exposed to the secondary side coolant. The staff finds the applicant's identification that loss of material due to erosion is an applicable aging effect for the components within the scope of this AMR acceptable because the applicant's analysis is at least as conservative as similarly made analyses in Section IV.D1 of GALL, Volume 2. The staff therefore concludes that the applicant's identification of aging effects in AMR Item 6 of LRA Table 3.1-2 is acceptable.

Evaluation—Aging Management Programs

The applicant identified the Water Chemistry Program to manage the aging effects of these components. The applicant stated that the Water Chemistry Program maintains strict controls on suspended solids in the feedwater system. These controls provide assurance that erosion will be managed. The general issue raised in Section 3.1.2.4.6.3 of this SER addresses the ability of water chemistry programs to manage loss of material and cracking in SG components without the need for confirmatory verification using inspection-based AMPs. Therefore, RAI 3.1.2.4.6-2 is also applicable to the management of loss of material due to erosion in the SG tube bundle wrappers and SG tubeplates that are fabricated from carbon steel, and the steam flow limiters that are made of nickel-based alloy, as discussed in LRA Table 3.1-2, Item 6.

Conclusions

The applicant has provided its AMR for loss of material due to erosion as the aging effect for SG components including the tube bundle wrapper, tubeplate, and steam flow limiter in AMR Item 6 of Table 3.1-2 of the LRA. The staff has reviewed the applicant's evaluation for AMR Item 6 of Table 3.1-2 and its response to RAI 3.1.2.4.6-2. The staff has determined that the applicant's AMR for this item is acceptable consistent with the staff's AMRs for loss of material in other SG components. On the basis of this review, the staff concludes that the applicant has demonstrated that the AMR for loss of material in the SG tube bundle wrapper, tubeplate, and steam flow limiter, as given in AMR Item 6 of Table 3.1-2 of the LRA, will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.1.2.4.6.6 Loss of Material, Cracking, and Changes in Material Properties in SG Snubber Reservoir Components—Evaluation of AMR Item 7 of LRA Table 3.1-2

Summary of Technical Information in the Application

The applicant provided its alternative AMR for evaluating loss of material, cracking, and changes in material properties in the RNP SG snubber reservoir components in AMR Item 7 of Table 3.1-2 of the LRA. Section IV.D1 of GALL, Volume 2, does not have a corresponding AMR analysis for SG snubber reservoir components used to support recirculating SGs.

In RAI 3.1.2.4.6-5, the staff asked the applicant to provide an explanation of why the SG snubber components, which are active, are included within the scope of AMR Item 7 of LRA Table 3.1-2. In RAI 3.1.2.4.6-6, the staff asked the applicant to identify which SG snubber components were within the scope of the AMR analysis in AMR Item 7 of LRA Table 3.1-2. In its response to RAI 3.1.2.4.6-5, dated April 28, 2003, the applicant stated, in part, that the SG support system includes hydraulic snubbers and the applicant conservatively included the passive portions of the SG snubber reservoir components within the scope of license renewal. In its response to RAI 3.1.2.4.6-6, dated April 28, 2003, the applicant clarified that the scope of AMR 7 to LRA Table 3.1-2 includes the following components that are subject to an AMR—snubber manifold, hydraulic control unit, flex hoses, and piping reservoir.

The applicant's responses to RAI 3.1.2.4.6-5 and 3.1.2.4.6-6 clarification of why the applicant has included the SG snubbers are within the scope of license renewal, and which of the SG snubber components are considered by the applicant to be passive and are in need of AMRs. The applicant's response to RAI 3.1.2.4.6-5 meets the criteria in 10 CFR 54.4 and is therefore acceptable. RAI 3.1.2.4.6-5 is resolved. The applicant's response to RAI 3.1.2.4.6-6 meets the AMR criteria of 10 CFR 54.21(a)(1) and is therefore acceptable. RAI 3.1.2.4.6-6 is resolved.

Evaluation—Identification of Aging Effects

In AMR Item 7 of Table 3.1-2 to the LRA, the applicant identified that loss of material, cracking, and changes in material properties are applicable aging effects for the passive, structural components for the SG snubber reservoirs. These aging effects are the aging effects the staff expects to occur in the SG snubber reservoir components during the lives of the components. Therefore, the staff concludes that the applicant's identification of aging effects for the SG snubber reservoir components is acceptable.

Evaluation—Aging Management Program

The applicant credits the Preventive Maintenance Program with managing all applicable aging effects for the passive, structural SG reservoir components within the scope of AMR 7 of Table 3.1-2. In RAI 3.1.2.4.6-7, the staff asked the applicant to provide an explanation on how the plant-specific Preventive Maintenance Program is sufficient to manage the applicable aging effects that have been identified for the snubber reservoir components within the scope of AMR Item 7 of LRA Table 3.1-2.

In its response to RAI 3.1.2.4.6-7, dated April 28, 2003, the applicant stated that preventive maintenance activities for the SG snubbers include visual inspections for the detection of leakage and for the determination of the physical state of the components, the inspections are performed at a frequency not to exceed 18 months, and the components are replaced as required. Snubbers used in support of safety-related structural components at light-water reactors are typically inspected using the inspections for the plant's Preventive Maintenance Program, as performed in accordance with approved plant procedures. The applicant's response to RAI 3.1.2.4.6-7 is consistent with this practice. The staff therefore concludes that the response to RAI 3.1.2.4.6-7 is acceptable, and RAI 3.1.2.4.6-7 is resolved.

Based on this analysis, the staff concludes that the Preventive Maintenance Program is an acceptable AMP for managing the aging effects that are applicable to the passive, structural SG snubber components. The Preventive Maintenance Program is discussed in Section B.3.18 of Appendix B of the LRA. The staff evaluates this program in Section 3.0.3 of the application.

Conclusions

AMR Item 7 of LRA Table 3.1-2 provides a supplemental AMR for assessing whether loss of material, cracking, and/or changes in material properties are applicable aging effects for the SG snubber reservoir components. Section IV.D1 of GALL, Volume 2, does not include any analogous AMRs for this AMR Item. Based on the staff's review of the applicant's analysis and the staff's independent assessment of this AMR item, the staff finds that the applicant has provided an acceptable basis for managing the applicable aging effects for the SG snubber reservoir components during the period of extended operation. On the basis of this review, the staff concludes that the applicant has demonstrated that loss of material, cracking, and/or changes in material properties will be adequately managed so that the SG snubber reservoir components will be maintained consistent with the CLB during the period of extended operation.

3.1.2.4.6.7 Cracking Due to SCC in the SG Lower Head Divider Plate and SG Tubeplate Cladding That Is Fabricated from Nickel-Based Alloy—Evaluation of AMR Item 11 of LRA Table 3.1-2

Summary of Technical Information in the Application

The applicant provides its AMR for cracking due to SCC of the SG lower head divider plate and tubeplate (tubesheet) cladding in AMR Item 11 of Table 3.1-2 of the LRA. Section IV of GALL, Volume 2, does not have a corresponding AMR for cracking due to SCC in these components.

Evaluation—Identification of Aging Effects

Although GALL, Volume 2, does not have a corresponding AMR for cracking due to SCC in these components, the AMR for commodity group item IV.D1.1-e states that cracking due to SCC is an applicable aging effect for the feedwater impingement plates and supports that are made from carbon steel and are exposed the secondary side coolant. While nickel-based alloys are normally designed to be resistant to the effects of SCC, the applicant has conservatively identified cracking due to SCC as an applicable aging effect for the steam flow limiters that are made from nickel-based alloy and are exposed to the secondary side coolant. The staff finds that the applicant's identification of aging effects for AMR 11 of LRA Table 3.1-2 is acceptable because the applicant's analysis is at least as conservative as analogous AMR analyses in Section IV.D1 of GALL, Volume 2. The staff therefore concludes that the applicant's identification of aging effects in AMR Item 11 of LRA Table 3.1-2 is acceptable.

Evaluation—Aging Management Programs

The applicant credited the Water Chemistry Program with managing crack initiation and growth due to SCC for the SG divider plates and tubeplate cladding. The applicant stated that the Water Chemistry Program has been proven effective in managing SCC because it controls the aggressive chemical species that cause the aging mechanism. The general issue raised in Section 3.1.2.4.6.3 of this SER addresses the ability of water chemistry programs to manage SCC in these SG components without the need for confirmatory verification using inspection-based AMPs. Therefore, RAI 3.1.2.4.6-2 and the staff's resolution of RAI 3.1.2.4.6-2 are also applicable to the management of cracking due to SCC in the SG divider plates and tubeplate cladding that are made of nickel-based alloy as discussed in LRA Table 3.1-2 Item 11. Therefore, the staff concludes that the Water Chemistry Program, as a mitigative type of program, alone is sufficient to manage cracking due to SCC in these components. The staff therefore concludes AMR 11 of LRA Table 3.1-2 is acceptable.

Conclusions

The applicant has provided its AMR for cracking due to SCC as the aging effect for the SG divider plates and tubeplate cladding in AMR Item 11 of Table 3.1-2 of the LRA. The staff has reviewed the applicant's evaluation for AMR Item 11 of LRA Table 3.1-2 and its response to RAI 3.1.2.4.6-2. The staff has determined that the applicant's AMR for this item is acceptable consistent with the staff's AMRs for SCC in other SG components. On the basis of this review, the staff concludes that the applicant has demonstrated that the AMR for cracking due to SCC in the steam generator lower head, divider plate and tubeplate cladding, as given AMR Item 11 of Table 3.1-2 of the LRA, will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.1.2.4.6.8 Loss of Mechanical Closure Integrity/Loss of Material Resulting from Aggressive Chemical Attack in SG Secondary Manway and Handhole Bolting Made from Carbon Steel—Evaluation of AMR Item 12 to LRA Table 3.1-2

Summary of Technical Information in the Application

The applicant provides its AMR for the SG secondary side manway and handhole bolting in AMR Item 12 of Table 3.1-2 of the LRA.

Evaluation—Identification of Aging Effects

In AMR Item 12 of Table 3.1-2 of the LRA, the applicant identified that SG secondary side manway and handhole bolting materials are fabricated from carbon steel and are exposed to the following external environments—containment air and borated water leaks. The applicant identified that loss of mechanical closure integrity due to aggressive corrosive attack (i.e., due to boric acid-induced corrosion or wastage) is an applicable aging effect for these components. Section IV.D1 of GALL, Volume 2, does not provide a corresponding AMR for boric acid corrosion (boric acid-induced wastage) in the external surfaces of carbon steel/low-alloy steel SG secondary side manway and handhole bolting materials. However, in AMR Item IV.D2.1-j of GALL, Volume 2, the staff identifies that loss of material due to boric acid corrosion is an applicable effect for the external surfaces of carbon steel and low-alloy steel pressure boundary and structural components (including secondary manway and handhole bolting) in once-through SGs. The applicant's identification that loss of mechanical closure integrity due to aggressive corrosive attack is an applicable aging effect for the SG secondary side manway and handhole bolting materials is consistent with AMR Item IV.D2.1-j of GALL, Volume 2, and is therefore acceptable to the staff.

CP&L has identified that loss of mechanical closure integrity due to aggressive corrosive attack is an applicable effect for the RNP secondary side manway and handhole bolting components and credited the Boric Acid Corrosion Program as the AMP for managing this aging effect in the bolts. Sections IV.D2.1-j and -k of GALL, Volume 2, identify that loss of mechanical closure integrity due to stress relaxation (i.e., loss of preload) is also an applicable aging effect for the secondary side manway and handhole bolting components, and states that the Bolting Integrity Program (GALL XI.M18) should be used to manage loss of preload in these bolts. However, the applicant has not identified that loss of mechanical closure integrity due to stress relaxation is an applicable effect for the SG secondary side manway and handhole bolting.

In RAI 3.1.2.4.6-3, the staff requested the applicant to provide its technical basis for concluding that loss of preload is not an applicable aging effect for the SG secondary side manway and handhole bolting components. In the RAI, the staff requested the applicant to amend its AMR for these components (AMR Item 12 of Table 3.1-2 of the LRA) and to propose an acceptable AMP if loss of preload due to stress relaxation is determined to be an applicable aging effect for the SG primary and secondary side manway and handhole bolting components. In RAI 3.1.2.4.6-4, the staff asked the applicant to confirm that either the yield strengths (and not minimum yield strengths) for heats of material used to fabricate the SG secondary side manway and handhole bolts, as ascertained from the certified material test reports (CMTRs) for the materials, are less than 150 ksi, or that the hardness levels for the bolting materials are less than 32 on a Rockwell C hardness scale, as ascertained from the CMTRs.

In its response to RAI 3.1.2.4.6-3, the applicant stated that its response to RAI 3.1.2.1-3 applies. Therefore, the applicant's resolution of RAI 3.1.2.1-3 is also applicable to the resolution of RAI 3.1.2.4.6-3 regarding whether stress relaxation should also be managed for the SG secondary manway and handhole bolting. In addition, the applicant's resolution of Confirmatory Item 3.1.2.1-1, Part 1, is also applicable to the determination as to whether SCC should be managed in the carbon steel SG secondary manway and handhole bolting. The staff's AMR evaluation for AMR Item 22 of LRA Table 3.1-1, as given in Section 3.1.2.1 of the SER, discusses aging of SG primary and secondary bolting.

The staff's evaluation of the applicant's identification of aging effects for the SG secondary manway and handhole bolting and determination as to whether AMR 12 of LRA Table 3.1-2 is pending acceptable resolution of RAI 3.1.2.1-3 by Confirmatory Item 3.1.2.1-1, Part 1.

Evaluation—Aging Management Programs

The applicant credited the Boric Acid Corrosion Program with managing loss of mechanical closure integrity due to aggressive corrosive attack during the extended period of operation for RNP. This is consistent with Section IV.D2.1-j of GALL, Volume 2, and is therefore acceptable to the staff. The applicant describes and discusses the RNP Boric Acid Corrosion Program in Section B.3.2 of Appendix B of the LRA. The staff evaluates the Boric Acid Corrosion Program in Section 3.0.3.4 of this SER. However, the staff's evaluation as to whether AMPs need to be credited for managing loss of preload due to stress relaxation, and cracking due to SCC in the SG secondary manway and handhole bolting, is pending acceptable resolution of RAI 3.1.2.1-3 by Confirmatory Item 3.1.2.1-1, Part 1.

The applicant has provided its AMR for loss of mechanical closure integrity/loss of material resulting from aggressive chemical attack in SG secondary manway and handhole bolting made from carbon steel in AMR Item 12 of Table 3.1-2 of the LRA. The staff has reviewed the applicant's evaluation for AMR Item 12 of Table 3.1-2 and its response to RAI 3.1.2.4.6-3 and 3.1.2.4.6-4. The staff requires further information for completion of its determination for this AMR item. The staff's determination for AMR 12 of LRA Table 3.1-2 is pending acceptable resolution of RAI 3.1.2.1-3 by Confirmatory Item 3.1.2.1-1, Part 1.

3.1.2.4.7 Reactor Vessel Level Instrumentation

The applicant's AMR for the SS non-Class 1 piping, tube, and fitting components in the RV level instrumentation lines is given in AMR Item 18 of LRA Table 3.1-2. The staff's evaluation of AMR Item 18 of LRA Table 3.1-2 is given in Section 3.1.2.4.1 of this SER.

3.1.2.4.8 Conclusions

On the basis of its review, the staff concludes that, the applicant has adequately identified the aging effects, and the AMPs credited for managing the aging effects, of the RCS plant specific components, such that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR Supplement program description and concludes that it provides an adequate program description of the AMPs credited for managing aging of the RCS plant specific components, as required by 10 CFR 54.21(d).

3.1.3 Evaluation Findings

The staff has reviewed the information in Section 3.1 of the LRA. On the basis of its review, the staff concludes that, pending satisfactory implementation of the commitments discussed above, the applicant has demonstrated that the aging effects associated with the components of the reactor systems will be adequately managed so that these components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). In addition, the staff also concludes that, pending satisfactory implementation of the commitments discussed above, the UFSAR Supplements for RNP provide an acceptable description of the programs and activities for managing the effects of aging of the components of the reactor systems for the period of extended operation, as required by 10 CFR 54.21(d).

3.2 Engineered Safety Features Systems

This section addresses the aging management of the components of the engineered safety features (ESF) systems group. The systems that make up the ESF system group are described in the following SER sections:

- Residual Heat Removal System (2.3.2.1)
- Safety Injection System (2.3.2.2)
- Containment Spray System (2.3.2.3)
- Containment Air Recirculation Cooling System (2.3.2.4)
- Containment Isolation System (2.3.2.5)

As discussed in Section 3.0.1 of this SER, the components in each of these ESF systems are included in one of two LRA tables. LRA Table 3.2-1 consists of ESF system components that are evaluated in the GALL Report and ESF system components that were not evaluated in the GALL Report, but the applicant has determined can be managed using a GALL AMR and associated AMP, and LRA Table 3.2-2 consists of ESF system components that are not evaluated in the GALL Report.

3.2.1 Summary of Technical Information in the Application

In LRA Section 3.2, the applicant described its AMRs for the ESF systems group at RNP. The description of the systems that comprise the ESF systems group can be found in LRA Section 2.3.2.

The passive, long-lived components in these systems that are subject to an AMR are identified in LRA Tables 2.3-2 through 2.3-6.

The applicant's AMRs included an evaluation of plant-specific and industry OE. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify aging effects that require management. These reviews concluded that the aging effects requiring management based on RNP OE were consistent with aging effects identified in GALL.

The applicant's review of industry OE included a review of OE through 2001. The results of this review concluded that aging effects requiring management based on industry OE were consistent with aging effects identified in GALL.

The applicant's ongoing review of plant-specific and industry-wide OE is conducted in accordance with the RNP Operating Experience Program.

3.2.2 Staff Evaluation

In Section 3.2 of the LRA, the applicant describes its AMR for the ESF systems. The staff reviewed LRA Section 3.2 to determine whether the applicant has provided sufficient information to demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB throughout the period of extended operation, in accordance with the requirements of 10 CFR 54.21(a)(3), for the ESF system components that are determined to be within the scope of license renewal and subject to an AMR.

The applicant referenced the GALL Report in its AMR. The staff has previously evaluated the adequacy of the aging management of ESF system components for license renewal as documented in the GALL Report. Thus, the staff did not repeat its review of the matters described in the GALL Report, except to ensure that the material presented in the LRA was applicable, and to verify that the applicant had identified the appropriate programs as described and evaluated in the GALL Report. The staff evaluated those aging management issues recommended for further evaluation in the GALL Report. The staff also reviewed aging management information submitted by the applicant that was different from that in the GALL Report or was not addressed in the GALL Report. Finally, the staff reviewed the UFSAR Supplement to ensure that it provided an adequate description of the programs credited with managing aging for the ESF system components.

In LRA Section 3.2, the applicant provided brief descriptions of the ESF systems and summarized the results of its AMR of the ESF systems at RNP.

Table 3.2-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.2 that are addressed in the GALL Report.

Table 3.2-1 Staff Evaluation for RNP Engineered Safety Features System Components in the GALL Report

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Piping, fittings, and valves in ECCS	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Consistent with GALL. GALL recommends further evaluation (see Section 3.2.2.2.1 below)
Piping, fittings, pumps, and valves in ECCS	Loss of material due to general corrosion	Water Chemistry and One-Time Inspection	Not applicable	BWR

Components in containment spray (PWR only), standby gas treatment (BWR only), containment isolation, and ECCS	Loss of material due to general corrosion	Plant specific	No AMP required	Only containment isolation components have material (carbon steel) consistent with GALL. Environment consideration eliminates identification of aging effects requiring management. GALL recommends further evaluation (see Section 3.2.2.2.2 below)
Piping, fittings, pumps, and valves in ECCS	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Not applicable	BWR
Components in containment spray (PWR only), standby gas treatment (BWR only), containment isolation, and ECCS	Loss of material due to pitting and crevice corrosion	Plant specific	Preventive Maintenance Program	Aging effects are identified for SS containment penetrations in raw water. Consistent with GALL. GALL recommends further evaluation (see Section 3.2.2.2.3 below)
Containment isolation valves and associated piping	Loss of material due to microbiologically influenced corrosion	Plant specific	Preventive Maintenance Program	For containment penetration components in liquid waste processing and IVSW. Consistent with GALL. GALL recommends further evaluation (see Section 3.2.2.2.4 below
Seals in standby gas treatment system	Seals in standby gas treatment system	Changes in properties due to elastomer degradation	Plant specific	Not applicable—BWR
WR HPSI (charging) pump miniflow orifice	Loss of material due to erosion	Plant specific	Not applicable	This component/commodity group is not applicable to RNP. (see Section 3.2.2.2.5 below)
External surface of carbon steel components	Loss of material due to general corrosion	Plant specific	System Monitoring Program and Boric Acid Corrosion Program	For carbon steel components subject to aggressive chemical attack. Consistent with GALL. GALL recommends further evaluation (see Section 3.2.2.2.6 below)
Drywell and suppression chamber spray system nozzles and flow orifices	Plugging of nozzles and flow orifices due to general corrosion	Plant specific	Not applicable	BWR
Piping and fittings of CASS in ECCS	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	Thermal Aging Embrittlement of CASS Program	This component/commodity group is evaluated under RCS CASS piping in Section 3.1.2.1 of this SER
Components serviced by open-cycle cooling system	Local loss of material due to corrosion and/or buildup of deposit due to biofouling	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System Program	Consistent with GALL (see Section 3.2.2.1 below)
Components serviced by closed-cycle cooling system	Loss of material due to general, pitting, and crevice corrosion	Closed-cycle Cooling Water System	Closed-cycle Cooling Water System Program	Consistent with GALL (see Section 3.2.2.1 below)

Emergency core cooling system valves and lines to and from HPCI and RCIC pump turbines	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	Not applicable	BWR
Pumps, valves, piping, and fittings in containment spray and ECCS	Crack initiation and growth due to SCC	Water Chemistry	Water Chemistry Program	Consistent with GALL (see Section 3.2.2.1 below)
Pumps, valves, piping, and fittings in ECCS	Crack initiation and growth due SCC and IGSCC	Water Chemistry and BWR SCC	Not applicable	BWR
Carbon steel components	Loss of material due to boric acid corrosion	Boric Acid Corrosion	Boric Acid Corrosion Program	Consistent with GALL (see Section 3.2.2.1 below)
Closure bolting in high pressure or high temperature systems	Loss of material due to general corrosion, loss of preload due to stress relaxation, and crack initiation and growth due to cyclic loading or SCC	Bolting Integrity	Boric Acid Corrosion Program	There are no bolts with specified minimum yield strength > 150 ksi in the ESF systems, and the Boric Acid Corrosion Program is used to manage loss of material due to boric acid corrosion. Bolting Integrity Program is not applicable to bolting for the RNP ESF systems.

The staff's review of the ESF systems for the RNP LRA is contained within four sections of this SER. Section 3.2.2.1 is the staff review of components in the ESF systems that the applicant indicates are consistent with GALL and do not require further evaluation. Section 3.2.2.2 is the staff review of components in the ESF systems that the applicant indicates are consistent with GALL and GALL recommends further evaluation. Section 3.2.2.3 is the staff evaluation of AMPs that are specific to the ESF systems group. Section 3.2.2.4 contains an evaluation of the adequacy of aging management for components in each system in the ESF systems group and includes an evaluation of components in the ESF systems that the applicant indicates are not in GALL.

3.2.2.1 Aging Management Evaluations in the GALL Report That Are Relied On for License Renewal, Which Do Not Require Further Evaluation

For component groups evaluated in GALL for which the applicant has claimed consistency with GALL, and for which GALL does not recommend further evaluation, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation. The staff also sampled component groups to determine whether the applicant had properly identified those component groups in GALL that were not applicable to its plant. Specifically, the staff sampled the following three inspection items conducted from June 9–3, 2003, and from June 23–27, 2003, for the ESF systems:

(20) In LRA Table 3.2-1, Item 2, the applicant stated that, "The RNP containment spray headers and valves are SS. Therefore, this evaluation is limited to containment isolation components." The audit was to confirm that the containment spray headers and valves are indeed made of SS material.

(21) In LRA Table 3.2-1, Item 8, the applicant stated that, "According to the GALL Report, this group consists of heat exchangers cooled by an open cycle cooling water system.

RNP does not have a heat exchanger that cools the containment spray to the containment." The audit was to confirm that the containment spray system does not have a heat exchanger that is serviced by open cycle cooling water system.

(22) In LRA Table 3.2-1, Item 12, the applicant stated that, "There are no bolts with specified minimum yield strength > 150 ksi in the ESF Systems." The inspection was to confirm this bolting material specification.

For Item 1, the inspection confirmed that the containment spray headers and valves are made of SS. The information reviewed included the revision of CP&L drawing no. 5379-1082LR, sheet 5, which details the piping to the containment spray headers. The piping codification is 6-SI-151R-41A, which is documented as SS material and listed in CPL-HBR2-M-047, Revision 4, "Specification for Pipe and Piping Related Products Material Requirements." For Item 2, based on the information provided in CPLC drawing no. 5379-1082LR, sheets 3 and 5, the inspection confirmed that the CSS does not have a heat exchanger that is serviced by an open cycle cooling water system. For Item 3, the audit reviewed the RNP UFSAR, Revision 16, Section 6.1, "Engineered Safety Features," which specifies that bolting material conforms with ASTM A193. The minimum yield strength for all grades of this type of bolting is below 150 ksi. The audit thus confirmed the bolting material specification.

The details of the staff's AMR inspection and audit can be found in AMR Inspection Report 50-261/2003-009 (ADAMS Accession Number ML032130040) and the audit report dated August 12, 2003.

On the basis of its review of the inspection and audit results, the staff finds that the applicant's claim of consistency with the GALL Report is acceptable, and that it is acceptable for the applicant to reference the information in the GALL Report for ESF system components. Therefore, on this basis, the staff concludes that the components for which the applicant claimed consistency with GALL will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2 Aging Management Evaluations in the GALL Report That Are Relied On for License Renewal, For Which GALL Recommends Further Evaluation

For component groups evaluated in GALL for which the applicant has claimed consistency with GALL, and for which GALL recommends further evaluation, the staff reviewed the applicant's evaluation to determine whether it adequately addressed the issues for which GALL recommended further evaluation. In addition, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation.

The GALL Report indicates that further evaluation should be performed for the components groups described in the following sections.

3.2.2.2.1 Cumulative Fatigue Damage

The GALL Report identifies fatigue as a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff reviewed the evaluation of this TLAA in Section 4.3 of this SER, following the guidance in Section 4.3 of the SRP-LR.

For the residual heat removal system (RHR), the applicant identified that TLAAs are applicable to the flow orifices/elements, RHR heat exchanger tubing, RHR pumps, RHR seal water heat exchanger tubing, and valves, piping, tubing, and fittings. The applicant discusses the TLAA in Section 4.3.1 of the LRA, "Reactor Coolant and Associated System Fatigue." This TLAA is evaluated in Section 4.3 of this SER.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of cumulative fatigue damage for components in the RHR system, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.2.2.2.2 Loss of Material Due to General Corrosion

Loss of material due to general corrosion could occur in the CSS header and spray nozzle components and the external surfaces of PWR carbon steel components. The GALL Report recommends further evaluation on a plant-specific basis to ensure that the aging effect is adequately managed for these components. The staff reviewed the applicant's proposed programs to ensure that an adequate program will be in place for the management of general corrosion of these components.

In LRA Table 3.2-1, Item 2 and Item 6, in the discussion column, the RNP AMR methodology assumed that the external surfaces of carbon steel components would not be susceptible to corrosion if they were located in areas protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack (e.g., borated water leakage). The staff found the above statement on environment to lack certainty. In RAI 3.2.1-1, the staff requested the applicant to ascertain the plant-specific environments, in which the applicant claimed that the equipment in this component/commodity group is considered to not be susceptible to general corrosion. By letter dated April 28, 2003, the applicant stated that the external surfaces of the carbon steel components that are included in LRA Table 3.2-1, Item 2 and Item 6, were determined to be subject to an environment of air-gas, not subject to condensation or aggressive chemical attack, and protected from weather. The external environment being referred to is typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant amounts of corrosion of carbon steel require an electrolytic environment, and a simultaneous presence of oxygen and moisture. Significant corrosion of carbon steel in an ambient air environment also requires the components to be subject to condensation. Without the presence of the aggressive environment, therefore, the applicant determined that carbon steel components will experience insignificant amounts of corrosion, and no aging effects would be applicable to this component/commodity group. The staff finds the applicant's response to be consistent with industry experience and acceptable.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of loss of material due to general corrosion for components in the applicable ESF systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.2.2.2.3 Local Loss of Material Due to Pitting and Crevice Corrosion

Local loss of material from pitting and crevice corrosion could occur in containment spray components, containment isolation valves and associated piping, and buried portions of the refueling water tank external surface. The GALL Report recommends further evaluation to ensure that the aging effect is adequately managed for these components. The staff reviewed the applicant's proposed programs to ensure that an adequate program will be in place for the management of local loss of material due to pitting and crevice corrosion of these components.

The applicant stated that loss of material due to pitting and crevice corrosion was identified as an aging effect for the SS valves, piping, and fittings in raw water associated with containment penetration. The applicant has used the plant-specific Preventive Maintenance Program to manage loss of material due to pitting and crevice corrosion. The program activities provide for periodic component replacement, inspections, and testing to detect any aging effects and mechanisms. The extent and schedule of the inspections and testing assure detection of component degradation prior to loss of their intended functions. Established techniques such as visual inspections are used. The staff reviewed the applicant's proposed program to ensure that pitting and crevice corrosion are not occurring and that the components' intended functions will be maintained during the period of extended operation.

In LRA Table 3.2-1, Item 3, the applicant stated that pitting and crevice corrosion are not creditable aging mechanisms for the exterior bottom of the SS refueling water storage tank (RWST), in part because the tank bottom sits on a layer of oiled sand. In RAI 3.2.1-3, the staff requested the applicant to discuss the merit of having the tank sitting on a layer of oiled sand. By letter dated April 28, 2003, the applicant stated that there is a 6 inch layer of oiled sand separating the tank bottom from compacted earth. The applicant stated that a review of industry documents confirms that past practice has been to use an oiled sand cushion under the tank in order to reduce tank bottom corrosion. The RNP evaluation for SS requires water intrusion for crevice or pitting corrosion to occur (in either oil or damp soil). As stated in the discussion for LRA Table 3.2-1, Item 3, pitting and crevice corrosion are not credible aging mechanisms for the exterior bottom of the RWST because (1) the tank location is well above the ground water elevation, (2) the area around the tank is well drained, and (3) the tank bottom sits on a layer of oiled sand. The RNP has reviewed the supporting AMR evaluation and determined that the presence of oil in the sand below the tank does not prevent, mitigate, nor contribute to age-related degradation such as crevice and pitting corrosion. For these aging effects to occur in SS, the RNP AMR evaluation requires the presence of an electrolyte (water contamination). As stated above, the bottom of the RWST is above grade and well above the ground water elevation, and flooding is not postulated at the plant (see UFSAR Section 2.4.1.1). Therefore, the applicant does not consider crevice or pitting corrosion to be credible aging mechanisms for the exterior surface of the RWST (including the tank bottom). The staff finds the applicant's response to be consistent with industry experience and acceptable.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of local loss of material due to pitting and crevice corrosion for components in the applicable ESF systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that there is reasonable assurance that this aging effect will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.4 Local Loss of Material Due to Microbiologically Influenced Corrosion

Local loss of material due to microbiologically influenced corrosion (MIC) could occur in PWR containment isolation valves and associated piping in systems that are not addressed in other chapters of the GALL Report. The GALL Report recommends further evaluation to ensure that the aging effect is adequately managed for these components. The staff reviewed the applicant's proposed programs to ensure that an adequate program will be in place for the management of local loss of material due to MIC of the containment isolation barriers.

In accordance with the GALL Report, this aging effect/mechanism is applicable only to containment isolation components exposed to a source of MIC. Applicable RNP components are containment penetration components in the liquid waste processing and isolation valve seal water systems conservatively assumed to be subjected to MIC. The applicant uses the plant-specific Preventive Maintenance Program to manage the aging effect/mechanism.

The program activities provide for periodic component replacement, inspections, and testing to detect any aging effects and mechanisms. The extent and schedule of the inspections and testing assure detection of component degradation prior to the loss of their intended functions. Established techniques such as visual inspections are used. The staff reviewed the applicant's proposed program to ensure that MIC is not occurring and that the component's intended function will be maintained during the period of extended operation.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of local loss of material due to MIC for components in the applicable ESF systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.2.2.2.5 Local Loss of Material Due to Erosion

Local loss of material due to erosion could occur in the high pressure safety injection (HPSI) pump miniflow orifice. This aging mechanism and effect will apply only to pumps that are normally used as charging pumps in the chemical and volume control systems (CVCS). The GALL Report recommends further evaluation to ensure that local loss of material is adequately managed for these components. The staff reviewed the applicant's proposed programs to ensure that an adequate program will be in place to manage this aging effect.

The RNP design does not include high head SI pumps. Charging is performed by positive displacement pumps in the CVCS. Therefore this issue does not apply to RNP ESF systems.

3.2.2.2.6 Loss of Material Due to General Corrosion

Loss of material due to general corrosion could occur in the external surfaces of carbon steel pipes and fittings, primary containment penetrations, and valve bodies of the containment penetrations and system interface system. This component type is only found in Table 2 of GALL (NUREG-1801, Vol. 1). It is not found in Table 3.2-1 of SRP (NUREG-1800). The GALL Report recommends further evaluation on a plant-specific basis to ensure that loss of material is adequately managed for these components. The staff reviewed the applicant's proposed programs to ensure that an adequate program will be in place for the management of general corrosion of these components.

The applicant stated that this discussion is applicable to the external surfaces of carbon and low-alloy steel components per GALL, Section V.E.1-b. In LRA Table 3.2-1, Item 2 and Item 6, in the discussion section, the RNP AMR methodology assumed that the external surfaces of carbon steel components would not be susceptible to corrosion if they were located in areas protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack (e.g., borated water leakage). The staff found the above statement on environment to lack affirmation. The staff's request for additional information for this issue is provided in RAI 3.2.1-1. The staff's discussion of this RAI and its resolution by the applicant are provided in Section 3.2.2.2.2 of this SER.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of loss of material due to general corrosion for components in the applicable RNP ESF systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.2.2.2.7 Conclusions

The staff has reviewed the applicant's evaluation of the issues for which GALL recommends further evaluation for components in the ESF systems. On the basis of its review, the staff concludes that the applicant has provided sufficient information to demonstrate that the issues for which GALL recommends further evaluation have been adequately addressed, and that the subject aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3). In addition, the staff concludes that the applicant's UFSAR Supplements provide adequate descriptions of the programs credited with managing these aging effects, as required by 10 CFR 54.21(d).

3.2.2.3 Aging Management Program for ESF System Components

In SER Section 3.2.2.1, the staff evaluated the applicant's conformance with the aging management program recommended by GALL for ESF systems. In SER Section 3.2.2.2, the staff reviewed the applicant's evaluation of the issues for which GALL recommends further evaluation. In this SER section, the staff presents its evaluation of the programs used by the applicant to manage the aging of the component groups within the ESF systems.

The applicant credits eight AMPs to manage the aging effects associated with components in the ESF systems. All eight AMPs are credited to manage aging for components in other system groups (common AMPs). The staff's evaluation of the common AMPs that are credited with managing aging in ESF system components is provided in Section 3.0.3 of this SER. The common AMPs are listed below:

- Fatigue Monitoring Program—SER Section 3.0.3.1
- Water Chemistry Program—SER Section 3.0.3.3
- Boric Acid Corrosion Program—SER Section 3.0.3.4
- Open-Cycle Cooling Water System Program—SER Section 3.0.3.7
- Closed-Cycle Cooling Water System Program—SER Section 3.0.3.8
- Selective Leaching of Material Program—SER Section 3.0.3.10
- Systems Monitoring Program—SER Section 3.0.3.11
- Preventive Maintenance Program—SER Section 3.0.3.12

3.2.2.4 Aging Management Review of Plant-Specific ESF System Components

In this section of the SER, the staff presents its review of the applicant's AMR for specific components within the ESF systems. To perform its evaluation, the staff reviewed the components listed in LRA Tables 2.3-2 to 2.3-6 to determine whether the applicant properly identified the applicable aging effects and the AMPs needed to adequately manage these aging effects. This portion of the staff's review involved identification of the aging effects for each ESF component, ensuring that each aging effect was evaluated in the appropriate LRA AMR table in Section 3, and that management of the aging effect was captured in the appropriate AMP. The results of the staff's review are provided below.

3.2.2.4.1 Residual Heat Removal System

3.2.2.4.1.1 Summary of Technical Information in the Application

The description of the RHR system can be found in Section 2.3.2.1 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-2. The components, aging effects, and AMPs are provided in LRA Tables 3.2-1 and 3.2-2.

<u>Aging Effects</u>

Table 2.3-2 of the LRA lists individual components of the RHR system that are within the scope of license renewal and subject to AMR. The components include bolting, flow orifices/elements, nitrogen cylinder tank(s), heat exchanger shell and cover, heat exchanger tubing, pump seal heat exchanger shell, pump(s), seal water heat exchanger tubing, and valves, piping, tubing, and fittings.

SS components are identified as subject to loss of material due to general, pitting, and crevice corrosion from the exposure to treated water (including steam). SS components are identified as subject to cracking initiation and growth due to SCC from the exposure to treated water (including steam). SS components are identified as subject to loss of heat transfer effectiveness due to fouling of heat transfer surfaces from exposure to treated water (including steam) environments.

Carbon steel components are identified as subject to loss of material due to general, pitting, and crevice corrosion from exposure to treated water (including steam). Carbon steel components are identified as subject to loss of material from aggressive chemical attack when exposed to indoor not-air-conditioned environments. Carbon steel bolting is identified as subject to loss of mechanical closure integrity from loss of material due to aggressive chemical attack. Carbon steel components are identified as subject to loss of material due to galvanic corrosion from exposure to treated water (including steam) environments.

Aluminum components are identified as subject to loss of material due to pitting and crevice corrosion, as well as aggressive chemical attack, from exposure to indoor not-air-conditioned, containment air, and borated water leakage environments.

The applicant determined that certain SS and copper alloy components have no aging effects requiring management for the environments of indoor not-air-conditioned, containment air, air and gas, or borated water leakage. This is because the applicable RNP environments do not promote concentration of contaminants or include exposure to aggressive chemical species, and because boric acid is not an aggressive chemical species for SS and copper alloys.

<u>Aging Management Programs</u>

The following AMPs are utilized to manage aging effects in the residual heat RHR system:

- Water Chemistry Program—SER Section 3.0.3.3
- Boric Acid Corrosion Program—SER Section 3.0.3.4
- Closed-Cycle Cooling Water System Program—SER Section 3.0.3.8

A description of these AMPs is provided in Appendix B of the LRA, and the TLAAs are discussed in Section 4.3.1 of the LRA.

3.2.2.4.1.2 Staff Evaluation

<u>Aging Effects</u>

The staff reviewed the information in LRA Tables 2.3-2, 3.2-1, and 3.2-2 for the RHR system. During its review, the staff determined that additional information was needed to complete its review.

LRA Table 2.3-2, Table 3.2-1, Item 11, and Table 3.1-1, Item 26, are referenced as links for closure bolting. Because Table 3.1-1 is for RCS, the staff requested, in RAI 3.2.1-6, that the applicant clarify the boundary interface, for closure bolting, between the RCS system and the RHR system. The staff also requested the applicant to confirm that an adequate AMR has been performed for the RHR closure bolting to ensure that a relevant material/environment combination, the aging effect requiring management, and the corresponding AMP are identified and documented. By letter dated April 28, 2003, the applicant stated that the closure bolting cross-reference to Table 3.1-1, Item 26, is incorrect in LRA Table 2.3-2, since the AMR results for ISI non-Class 1 components in the RHR system are provided in LRA Tables 3.2-1 and 3.2-2, not in LRA Table 3.1-1. This occurred because the tag number (RHR-MISC-PIPE), which was used to represent ISI non-Class 1 closure bolting in the RHR system, is also classified as ISI Class 1. The situation is analogous to the issue on the SI closure bolting raised in RAI 3.2.1-4, where the staff questioned the boundary interface relationship between the closure bolting located in the RCS and the non-Class 1 systems (such as RHR and SI systems), and how the AMR of closure bolting is addressed in the SI system. The same discussion applies to how closure bolting is addressed in the RHR system. The staff's discussion of this RAI and its resolution by the applicant is documented in Section 3.2.2.4.2.2 of this SER. For the RHR system here, the applicant was able to conclude that based on the RHR system and RCS AMRs reviewed, appropriate materials, environment, and aging effects have been identified, and appropriate programs were selected to manage the aging effects. The applicant's response clarifies the boundary interface between the closure bolting in the RCS system and those in the RHR system, and confirms that an adequate AMR has been performed for the RHR closure bolting. On this basis, the staff considers the applicant's response to be acceptable.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's response to the above RAI, the staff finds that the aging effects that result from contact of the RHR system SCs with the environments described in LRA Tables 2.3-2, 3.2-1, and 3.2-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the RHR system.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the RHR system:

- Water Chemistry Program
- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Program

These AMPs are credited for managing the aging effects of components in several structures and systems and, therefore, are considered common AMPs. The staff has evaluated these common AMPs and has found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Sections 3.0.3.3, 3.0.3.4, and 3.0.3.8, respectively, of this SER.

The fatigue of the RHR components is addressed by the TLAAs in Section 4.3.1 of the LRA, "Reactor Coolant and Associated System Fatigue." This TLAA is evaluated in Section 4.3 of this SER.

After evaluating the applicant's AMR for each of the components in the RHR system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.2-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in Table 3.2-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs and TLAAs to manage the aging effects for the materials and environments associated with the RHR system.

3.2.2.4.2 Safety Injection System

3.2.2.4.2.1 Summary of Technical Information in the Application

The description of the SI system can be found in Section 2.3.2.2 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-3. The components, aging effects, and AMP are provided in LRA Tables 3.2-1 and 3.2-2.

Aging Effects

Table 2.3-3 of the LRA lists individual components of the SI system that are within the scope of license renewal and subject to AMR. The components include tank, bolting, filter, equipment frames and housing, flow orifices/elements, heat exchanger shell, pump, heat exchanger tubing, heat exchanger shell and cover, and valves, piping, tubing, and fittings.

SS components are identified as subject to loss of material due to pitting and crevice corrosion from the exposure to treated water (including steam). SS components are identified as subject to loss of heat transfer effectiveness due to fouling of heat transfer surfaces from exposure to treated water (including steam) environments.

Carbon steel components are identified as subject to loss of material due to general corrosion from exposure to aggressive chemical attack. The carbon steel bolting is identified as subject to loss of material due to boric acid corrosion, which can lead to loss of mechanical closure integrity from loss of material due to aggressive chemical attack. Carbon steel components in raw water are identified as subject to flow blockage from fouling, loss of heat transfer effectiveness from fouling of heat transfer surfaces, loss of material from general, crevice, and pitting corrosion, and MIC. Carbon steel components are identified as subject to loss of material due to general, pitting, and crevice corrosion from exposure to treated water (including steam). Carbon steel components are identified as subject to local loss of material due to corrosion and/or buildup of deposit due to biofouling from exposure to raw water. Carbon steel components are identified as subject to loss of material due to galvanic corrosion and selective leaching from exposure to raw water. Carbon steel components are identified as subject to loss of material due to galvanic corrosion from exposure to treated water (including steam).

The applicant determined that certain SS has no aging effects requiring management for the environments of indoor not-air-conditioned, containment air, air and gas, or borated water leakage. This is because the applicable RNP environments do not promote concentration of contaminants or include exposure to aggressive chemical species, and that boric acid is not an aggressive chemical species for SS. In addition, no aging effects requiring management have been identified for carbon steel in lubricating oil with no water contamination.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the SS system:

- Water Chemistry Program—SER Section 3.0.3.3
- Boric Acid Corrosion Program—SER Section 3.0.3.4
- Open-Cycle Cooling Water System Program—SER Section 3.0.3.7
- Closed-Cycle Cooling Water System Program—SER Section 3.0.3.8

- Selective Leaching of Material Program—SER Section 3.0.3.10
- Systems Monitoring Program—SER Section 3.0.3.11

A description of these AMPs is provided in Appendix B of the LRA.

3.2.2.4.2.2 Staff Evaluation

Aging Effects

The staff reviewed the information in LRA Tables 2.3-3, 3.2-1, and 3.2-2 for the SI system. During its review, the staff determined that additional information was needed to complete its review. The staff's request for additional information is provided in RAI 3.2.1-1 for the applicant's confirmation of the assumed environments of external surfaces of carbon steel components. The staff's discussion of this RAI and its resolution by the applicant are provided in Section 3.2.2.2.2 of this SER.

For the safety injection system, LRA Table 3.2-1, Item 3, states that pitting and crevice corrosion are not a credible aging mechanism for the exterior bottom of the SS RWST, in part because the tank bottom sits on a layer of oiled sand. The staff's RAI is provided in RAI 3.2.1-3 for the issue of potential corrosion of tank bottom. The staff's discussion of this RAI and its resolution by the applicant are provided in Section 3.2.2.2.3 of this SER.

For closure bolting in the SI system, LRA Table 2.3-3 provides links to Table 3.2-1, Item 11, and Table 3.1-1, Item 26. The latter item addresses closure bolting in the RCS. For closure bolting in the CSS, LRA Table 2.3-4 provides links to LRA Table 3.2-1, Item 6 and 11. These two items address corrosion due to aggressive chemical attack resulting from leakage of sodium hydroxide (NaOH) and leakage of boric acid solution, respectively. In RAI 3.2.1-4, the staff requested the applicant to explain why, for closure bolting in the SI system (Table 2.3-3), Table 3.1-1, Item 26, is referenced, instead of Table 3.2-1, Item 6. The staff also requested the applicant to discuss how the AMR is performed for the closure bolting located in RCS, SI, and Containment Spray (CS) systems, and to explain the interface among the three systems. In addition, the staff requested the applicant to substantiate that all potential aging effects requiring management for the closure bolting are identified and adequately managed. By letter dated April 28, 2003, the applicant stated that portions of the SI system include components that implement CS system functions. Therefore, components/commodities subject to an AMR may be listed in either LRA Table 2.3-3 or Table 2.3-4, and the AMR results are included in LRA Tables 3.2-1 and 3.2-2. Since they do not directly connect to the RCS piping, there are no ISI Class 1 components in the CS system. On the other hand, there is a portion of the SI system piping and valves (including closure bolting) that connects to the RCS piping and is classified as ISI Class 1. These Class 1 components in the SI system were evaluated in the RCS AMR, and the AMR results are reported in LRA Tables 3.1-1 and 3.1-2. The RCS AMR defined closure bolting to include the affected RCS components and the interfacing systems components that are ISI Class 1 (e.g., ISI Class 1 components having closure bolting in the RHR system, CVCS, and the SI system).

The applicant stated that in LRA Table 2.3-3, the references for closure bolting in the SI system should also refer to Table 3.2-1, Item 6, which is supported by the SI system AMR. However, the reference to Table 3.1-1, Item 26, is inconsistent with the SI system AMR, which only applies to ISI non-Class 1 components, and, therefore, should be deleted. The applicant stated that non-Class 1 components having closure bolting in the SI system and located in the reactor auxiliary building (RAB) are also potentially subject to aggressive chemical attack from NaOH. Therefore, closure bolting in LRA Table 2.3-3 should also include; reference to LRA Table 3.2-1, Item 6. As noted above, the SI system includes components that perform the CS system function. The reference to LRA Table 3.2-1, Item 6, in LRA Table 2.3-3, was inadvertently omitted when the applicant divided the SI system components between LRA Tables 2.3-3 and 2.3-4.

The staff finds the applicant's response to RAI 3.2.1-4 to be acceptable, since the applicant has satisfactorily explained the interface relationship among RCS, SI, and CS systems for closure bolting, and has confirmed that all potential aging effects requiring management for the SI closure bolting are identified and adequately managed.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's responses to the above RAIs, the staff finds that the aging effects that result from contact of the SI system SCs to the environments described in LRA Tables 2.3-3, 3.2-1, and 3.2-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the SI system.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the SI system:

- Water Chemistry Program
- Boric Acid Corrosion Program
- Open-Cycle Cooling Water System Program
- Closed-Cycle Cooling Water System Program
- Selective Leaching of Material Program
- Systems Monitoring Program

These AMPs are credited for managing the aging effects of components in several structures and systems and, therefore, are considered common AMPs. The staff has evaluated these common AMPs and has found them to be acceptable for managing the aging effects identified for this system. These AMPs are evaluated in Sections 3.0.3.3, 3.0.3.4, 3.0.3.7, 3.0.3.8, 3.0.3.10 and 3.0.3.11, respectively, of this SER.

After evaluating the applicant's AMR for each of the components in the SI system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.2-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in Table 3.2-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the SI system.

3.2.2.4.3 Containment Spray System

3.2.2.4.3.1 Summary of Technical Information in the Application

The description of the CSS can be found in Section 2.3.2.3 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-4. The components, aging effects, and AMPs are provided in LRA Tables 3.2-1 and 3.2-2.

Aging Effects

Table 2.3-4 of the LRA lists individual components of the CSS that are within the scope of license renewal and subject to AMR. The components include bolting, flow orifices/elements, heat exchanger shell and cover, heat exchanger tubing, RHR pump seal heat exchanger shell, pump(s), eductors, tank, as well as valves, piping, tubing, and fittings.

SS components are identified as being subject to loss of material due to pitting and crevice corrosion from exposure to treated water (including steam). SS components are identified as being subject to loss of heat transfer effectiveness due to fouling of heat transfer surfaces from exposure to treated water (including steam) environments.

Carbon steel components are identified as being subject to loss of material due to general corrosion from exposure to aggressive chemical attack. The carbon steel bolting is identified as being subject to loss of material due to boric acid corrosion, which can lead to loss of mechanical closure integrity from loss of material due to aggressive chemical attack. Carbon steel components are identified as being subject to general corrosion, and pitting and crevice corrosion from exposure to treated water (including steam). Carbon steel components are identified as being subject to loss of material due to galvanic corrosion and selective leaching from exposure to treated water (including steam) environments.

The applicant determined that certain SS components have no aging effects requiring management for the environments of indoor not-air-conditioned, containment air, air and gas, or borated water leakage. The applicant formed its determination on the basis that the applicable RNP environments do not promote concentration of contaminants or include exposure to aggressive chemical species, and that boric acid is not an aggressive chemical species for SS.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the CSS:

- Water Chemistry Program—SER Section 3.0.3.3
- Boric Acid Corrosion Program—SER Section 3.0.3.4
- Closed-Cycle Cooling Water System Program—SER Section 3.0.3.8
- Systems Monitoring Program—SER Section 3.0.3.11

A description of these AMPs is provided in Appendix B of the LRA.

3.2.2.4.3.2 Staff Evaluation

Aging Effects

The staff reviewed the information in LRA Tables 2.3-4, 3.2-1, and 3.2-2 for the CSS. During its review, the staff determined that additional information was needed to complete its review. The staff's RAI is provided in RAI 3.2.1-1 for the applicant's confirmation of the assumed environments of external surfaces of carbon steel components. The staff's discussion of this RAI and its resolution by the applicant are provided in Section 3.2.2.2.2 of this SER. The staff's RAI is also provided in RAI 3.2.1-4 for the interfacing AMR of closure bolting located in RCS, SI, and CS systems. The staff's discussion of this RAI and its resolution by the applicant are provided in Section 3.2.2.4.2.2 of this SER.

The applicant stated that during the AMR, portions of the in-scope CS system are included as part of the SI system. To ensure that all of the CSS components, as listed in Table 2.3-4, have been evaluated, the staff requested in RAI 3.2.1-5 that the applicant confirm that adequate AMR has been performed for all the CSS components, to ensure that the relevant material/environment combinations, the aging effects requiring management, and the corresponding AMPs are identified and documented. By letter dated April 28, 2003, the applicant stated that the SI system includes components that perform the CS function. The components in the SI system that perform the CS system intended functions inject coolant into the RCS, and spray coolant containing borated water and NaOH solution into containment. The SI system AMR addresses SI and CS systems components under a system designation of "System No. 2080." The results for the ISI Class 1 piping components in the SI system are evaluated in the RCS AMR and are, therefore, reported in LRA Tables 3.1-1 and 3.1-2. The results of the ISI non-Class 1 piping components in the SI (and, hence, CS) system are reported in the LRA Tables 3.2-1 and 3.2-2. The applicant stated that in LRA Table 2.3-4, "spray additive tank" has correctly referenced LRA Table 3.2-1, Item 6, and Table 3.2-2, Item 1. However, the reference to LRA Table 3.2-1, Item 11, for spray additive tank and its associated closure bolting, is incorrect, as there are no potential borated water leakage sources in the spray additive tank room. The applicant stated that the valves, piping, tubing, and fittings in the CS system that required an AMR are SS, instead of carbon steel. Therefore, the reference of Table 3.2-1, Item 6, in LRA Table 2.3-4, for the valves, piping, tubing, and fittings is incorrect and should be deleted. The applicant also stated that containment vessel (CV) spray pump seal heat exchanger shell and cover are made of carbon steel. Its external surface is subject to indoor and potential leakage of boric acid (see LRA Table 2.3-4 and Table 3.2-1, Item 11), and the system AMR indicates that the aging effect of loss of material is managed by the Boric Acid Corrosion Program. The internal surface of the component is subject to CCW environments, and the AMR results are discussed in LRA Table 3.2-1 (Item 9) and Table 3.2-2 (Items 5 and 6), as referenced in LRA Table 2.3-4. Based on the applicant's description of the AMR performed for the CS system components, under the system designation of "System No. 2080," the staff considers the applicant's response to ensure that the relevant material/environment combinations, the aging effects requiring management, and the corresponding AMPs are identified and documented for the CSS components, and is, therefore, acceptable.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the above RAIs, the staff finds that the aging effects that result from contact of the CSS SCCs with the environments described in LRA Tables 2.3-4, 3.2-1, and 3.2-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the CSS.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the CSS:

- Water Chemistry Program
- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Program
- Systems Monitoring Program

These AMPs are credited for managing the aging effects of components in several structures and systems and, therefore, are considered common AMPs. The staff has evaluated these common AMPs and has found them to be acceptable for managing the aging effects identified for this system. These AMPs are evaluated in Sections 3.0.3.3, 3.0.3.4, 3.0.3.8, and 3.0.3.11, respectively, of this SER.

After evaluating the applicant's AMR for each of the components in the CSS, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.2-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in Table 3.2-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the CSS.

3.2.2.4.4 Containment Air Recirculation Cooling System

3.2.2.4.4.1 Summary of Technical Information in the Application

The description of the containment air recirculation cooling system can be found in Section 2.3.2.4 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-5. The components, aging effects, and AMPs are provided in LRA Tables 3.2-1 and 3.2-2.

Aging Effects

Table 2.3-5 of the LRA lists individual components of the containment air recirculation cooling system that are within the scope of license renewal and subject to AMR. The components include closure bolting, equipment frames and housings, flexible collars, heating/cooling coils, valves, ductwork and fittings, and damper mounting.

SS heating/cooling coils are identified as subject to flow blockage from fouling, and to loss of heat transfer effectiveness from fouling of heat transfer surfaces due to exposure to raw water. SS components are identified as subject to loss of material due to pitting and crevice corrosion and MIC from exposure to raw water. SS components are identified as subject to loss of material, on the internal surfaces, due to pitting and crevice corrosion and MIC from exposure to borated water environments.

Carbon steel bolting is identified as subject to loss of material from aggressive chemical attack, and loss of mechanical closure integrity from loss of material due to aggressive chemical attack. Carbon steel components are identified as subject to loss of material due to general corrosion, and pitting and crevice corrosion from exposure to indoor not-air-conditioned, containment air, and borated water leakage. Carbon steel components are identified as subject to loss of material due to aggressive chemical attack, and to loss of mechanical closure integrity from loss of material due to aggressive chemical attack.

Elastomers in indoor not-air-conditioned, containment air, and borated water leakage environments are identified as subject to cracking and change in material properties from elevated temperature, and cracking and change in material properties from irradiation embrittlement.

The applicant determined that external surfaces of carbon steel valves are not susceptible to corrosion if they were located in areas protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack. The applicant determined that galvanized steel components, such as damper mounting, equipment frames and housings, and ductwork and fittings, would experience no age-related degradation requiring management in the environments of indoor not-air-conditioned, containment air, and borated water leakage. In addition, SS components are not susceptible to any aging effects requiring management from exposure to indoor not-air-conditioned, containment air, air and gas, borated water leakage, and outdoor environment. The applicant stated that the applicable RNP environments do not promote concentration of contaminants or include exposure to aggressive chemical species, and that boric acid is not an aggressive chemical species for SS.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-4, the applicant to provide the basis for not considering boric acid corrosion as an applicable aging effect for galvanized steel components included in Table 3.3-1, row 20. The response was provided by letter dated April 28, 2003. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.4 of this SER, and is characterized as resolved.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the containment air recirculation cooling system:

- Boric Acid Corrosion Program—SER Section 3.0.3.4
- Open-Cycle Cooling Water System Program—SER Section 3.0.3.7
- Systems Monitoring Program—SER Section 3.0.3.11
- Preventive Maintenance Program—SER Section 3.0.3.12

A description of these AMPs is provided in Appendix B of the LRA.

3.2.2.4.4.2 Staff Evaluation

Aging Effects

The staff reviewed the information in LRA Tables 2.3-5, 3.2-1, and 3.2-2 for the containment air recirculation cooling system. During its review, the staff determined that additional information was needed to complete its review.

The staff noted in LRA Table 2.3-5 that valves" are included in LRA Table 3.3-2, Item 19, for the external surfaces of carbon steel components in assumed environments. In RAI 3.2.1-1, the staff requested the applicant to confirm the environments for these carbon steel components. The staff's discussion of this RAI and its resolution by the applicant are provided in Section 3.2.2.2.2 of this SER.

For the containment air recirculation cooling system, LRA Table 3.3-1, Items 2, 5, 13, and 16 are referenced in LRA Table 2.3-5 as links for flexible collars, equipment frames and housings, closure bolting, valves, and heating/cooling coils. Since Table 3.3-1 addresses component/commodity groups in the auxiliary system, the staff requested in RAI 3.2.1-7 that the applicant clarify that adequate AMRs have been performed for the above components, and that relevant material/environment combinations are considered, the aging effects requiring management are identified, and that the corresponding AMPs are identified and documented. By letter dated April 28, 2003, the applicant confirmed that AMRs have been performed for the containment air recirculation cooling system, under "System No. 8150—HVAC containment building systems." The applicant provided the AMPs utilized to manage the identified aging effects. The AMR evaluated each of the component/commodity groups by identifying the material and environment combinations that each might experience. The staff considers the applicant's response to be acceptable, since the AMR has been appropriately performed for the components of the containment air recirculation cooling system, and appropriate programs have been identified to address the aging effects requiring management.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's responses to the above RAIs, the staff finds that the aging effects that result from contact of the containment air recirculation cooling system SCs with the environments described in LRA Tables 2.3-5, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the containment air recirculation cooling system.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the containment air recirculation cooling system:

- Boric Acid Corrosion Program
- Open-Cycle Cooling Water System Program
- Systems Monitoring Program
- Preventive Maintenance Program

These AMPs are credited for managing the aging effects of components in several structures and systems and, therefore, are considered common AMPs. The staff has evaluated these common AMPs and has found them to be acceptable for managing the aging effects identified for this system. These AMPs are evaluated in Sections 3.0.3.4, 3.0.3.7, 3.0.3.12, and 3.0.3.12, respectively, of this SER.

After evaluating the applicant's AMR for each of the components in the containment air recirculation cooling system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.2-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in Table 3.2-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the containment air recirculation cooling system.

3.2.2.4.5 Containment Isolation System

3.2.2.4.5.1 Summary of Technical Information in the Application

The description of the containment isolation system can be found in Section 2.3.2.5 of this SER. The process systems whose only license renewal intended function is the containment isolation function are as follows:

- post accident hydrogen system
- service air system
- process/area radiation monitoring
- containment pressure relief system
- containment vacuum breaker system
- liquid waste processing system
- penetration pressurization local leak rate test
- isolation valve seat water system

The passive, long-lived components in each of these systems that are subject to an AMR are identified in LRA Table 2.3-6. The components, aging effects, and AMPs are provided in LRA Tables 3.2-1 and 3.2-2.

<u>Aging Effects</u>

Table 2.3-6 of the LRA lists individual components of the containment isolation system that are within the scope of license renewal and subject to AMR. The components include closure bolting and valves, piping, and fittings.

SS components are identified as being subject to loss of material due to crevice and pitting corrosion and MIC from exposure to raw water. SS components are identified as being subject to loss of material from crevice and pitting corrosion when exposed to treated water (including steam). Carbon steel components are identified as being subject to loss of material due to aggressive chemical attack, and loss of mechanical closure integrity from loss of material due to aggressive chemical attack. Aluminum components are identified as being subject to loss of material due to aggressive chemical attack, crevice corrosion, and pitting corrosion from exposure to borated water leakage.

The applicant stated that SS and copper alloy components are not susceptible to aging effects from exposure to borated water leakage because boric acid is not an aggressive chemical species for SS and copper alloy. The applicant stated that aluminum valves are not susceptible to aging effects requiring management in an air and gas environment. This is because the applicable RNP environments do not promote concentration of contaminants or include exposure to aggressive chemical attack. The applicant also stated that external surfaces of carbon steel valves, piping, and fittings are not susceptible to corrosion if they were located in areas protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack (e.g., borated water leakage).

Aging Management Programs

The following AMPs are utilized to manage aging effects in the containment isolation system:

- Water Chemistry Program—SER Section 3.0.3.3
- Boric Acid Corrosion Program—SER Section 3.0.3.4
- Preventive Maintenance Program—SER Section 3.0.3.12

A description of these AMPs is provided in Appendix B of the LRA.

3.2.2.4.5.2 Staff Evaluation

Aging Effects

The staff reviewed the information in LRA Tables 2.3-6, 3.2-1, and 3.2-2 for the containment isolation system. During its review, the staff determined that additional information was needed to complete its review. The staff's request for additional information is provided in RAI 3.2.1-1 for the applicant's confirmation of the assumed environments of external surfaces of carbon steel components. The staff's discussion of this RAI and its resolution by the applicant are provided in Section 3.2.2.2.2 of this SER.

In LRA Table 2.3-6 and Table 3.2-1, Items 3 and 4, the applicant credited the Preventive Maintenance Program for managing aging effects of loss of material due to pitting and crevice corrosion, MIC, and biofouling for the SS valves, piping, and fittings in raw water associated with containment penetration. In Appendix B.3.18,"Preventive Maintenance Program," the applicant included leaking and physical condition" as a parameter to be monitored and trended. In RAI 3.2.1-8, the staff questioned the potential for compromising the pressure boundary integrity in the presence of fluid leakage. The staff requested the applicant to clarify whether any of these components for which the Preventive Maintenance Program is credited for managing the aging effects relies on the monitoring of fluid leakage. In addition, the staff requested the applicant to provide a discussion on the operating history of these components to demonstrate that the associated aging effects will be adequately managed prior to the components' loss of intended pressure-retaining function. By letter dated April 28, 2003, the applicant stated that for the issue regarding the inclusion of leakage in the *Monitoring and Trending* element, refer to the discussion of leakage in the applicant's response to RAI 3.3-5.

The staff's discussion of this RAI and its resolution by the applicant are provided in Section 3.3.2.4.16.2 of this SER. For the operating history of the affected components listed in LRA Table 2.3-6 (liquid waste processing and isolation valves seal water (IVSW) systems), the applicant has found no occurrence of degradation attributable to the effects of aging. This is acceptable to the staff.

In response to the RAI 2.3.2.5-1, the applicant has decided to place the hydrogen recombiner, associated temporary flexible piping, and passive components required to open the Post Accident Hydrogen System (PAHS) containment isolation valves in scope for license renewal. As a result, additional components (valves, piping, and fittings) and corresponding AMR links were added to Tables 2.3-6, 3.2-1, and 3.2-2. Specifically, an additional item, Item 15, is added to the revised Table 3.2-2, which, in turn, is referenced in the revised Table 2.3-6, to address the AMR of the copper alloy valves, tubing, and fittings in the indoor not-air-conditioned, air, and gas environments. The applicant has identified no aging effect requiring management for the components under this material/environment combination. This is because the applicable RNP environment does not promote concentration of contaminants or include exposure to aggressive chemical species. An additional AMR link, Table 3.2-1, Item 11, was also added to the revised Table 2.3-6 to address the AMR of the carbon steel piping, valves, and fittings associated with potential boric acid corrosive environments. These components are managed in the same way the carbon steel piping, valves, and fittings in the safety injection system and containment spray system are managed, using the Boric Acid Corrosion Program. The staff has reviewed the above additional information provided in the applicant's letter of September 16, 2003, and finds that the evaluation it performed for the containment isolation system is not affected by the expansion of the system review scope. Based on the above, Confirmatory Item 2.3.2.5-1 is, therefore, closed.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's responses to RAIs 3.2.1-1, 3.2.1-3, 3.2.1-8, 3.3-5, and RAI 2.3.2.5-1, the staff finds that the aging effects resulting from contact of the containment isolation system SCs to the environments described in LRA Tables 2.3-6, 3.2-1, and 3.2-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the containment isolation system.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the containment isolation system:

- Water Chemistry Program
- Boric Acid Corrosion Program
- Preventive Maintenance Program

These AMPs are credited for managing the aging effects of components in several structures and systems and, therefore, are considered common AMPs. The staff has evaluated these common AMPs and has found them to be acceptable for managing the aging effects identified for this system. These AMPs are evaluated in Sections 3.0.3.3, 3.0.3.4, and 3.0.3.12, respectively, of this SER.

After evaluating the applicant's AMR for each of the components in the containment isolation system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.2-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in Table 3.2-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the containment isolation system.

3.2.2.4.5.3 Conclusions

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited for managing the aging effects of the ESF plant specific components discussed in Sections 3.2.2.4.1 through 3.2.2.4.5, such that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that it provides an adequate program descriptions of the AMPs credited for managing aging of the ESF plant specific components, as required by 10 CFR 54.21(d).

3.2.3 Evaluation Findings

The staff has reviewed the information in Section 3.2 of the LRA. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects and the AMPs credited for managing the aging effects for the ESF systems, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation. The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited for managing aging effects, as required by 10 CFR 54.21(d).

3.3 Auxiliary Systems

This section addresses the aging management of the components of the auxiliary systems group. The systems that make up the auxiliary systems group are described in the following SER sections:

- Sampling System (2.3.3.1)
- Service Water System (2.3.3.2)
- Component Cooling Water System (2.3.3.3)
- Chemical and Volume Control System (2.3.3.4)
- Instrument Air System (2.3.3.5)
- Nitrogen Supply/Blanketing System (2.3.3.6)
- Radioactive Equipment Drains (2.3.3.7)
- Primary and Demineralized Water System (2.3.3.8)
- Spent Fuel Pool Cooling System (2.3.3.9)
- Containment Purge System (2.3.3.10)

- Rod Drive Cooling System (2.3.3.11)
- HVAC Auxiliary Building (2.3.3.12)
- HVAC Control Room Area (2.3.3.13)
- HVAC Fuel Handling Building (2.3.3.14)
- Fire Protection System (2.3.3.15)
- Diesel Generator System (2.3.3.16)
- Dedicated Shutdown Diesel Generator (2.3.3.17)
- EOF/TSC Security Diesel Generator (2.3.3.18)
- Fuel Oil System (2.3.3.19)

As discussed in Section 3.0.1 of this SER, the components in each of these auxiliary systems are included in one of two LRA tables. LRA Table 3.3-1 consists of auxiliary system components that are evaluated in the GALL Report, and auxiliary system components that were not evaluated in the GALL Report but the applicant has determined can be managed using a GALL AMR and associated AMP. LRA Table 3.3-2 consists of auxiliary system components that are not evaluated in the GALL Report.

3.3.1 Summary of Technical Information in the Application

In LRA Section 3.3, the applicant described its AMRs for the auxiliary systems group at RNP. The description of the systems that comprise the auxiliary systems group can be found in LRA Section 3.3. The passive, long-lived components in these systems that are subject to an AMR are identified in LRA Tables 2.3-7 through 2.3-25.

The applicant's AMRs included an evaluation of plant-specific and industry OE. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify aging effects that require management. These reviews concluded that the aging effects requiring management based on RNP OE were consistent with aging effects identified in GALL.

The applicant's review of industry OE included a review of OE through 2001. The results of this review concluded that aging effects requiring management based on industry OE were consistent with aging effects identified in GALL.

The applicant's ongoing review of plant-specific and industry-wide OE is conducted in accordance with the RNP Operating Experience Program.

3.3.2 Staff Evaluation

In Section 3.3 of the LRA, the applicant describes its AMR for the auxiliary systems at RNP. The staff reviewed LRA Section 3.3 to determine whether the applicant has provided sufficient information to demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation, in accordance with the requirements of 10 CFR 54.21(a)(3), for the auxiliary system components that are determined to be within the scope of license renewal and subject to an AMR.

The applicant referenced the GALL Report in its AMR. The staff has previously evaluated the adequacy of the aging management of auxiliary system components for license renewal as documented in the GALL Report. Thus, the staff did not repeat its review of the matters described in the GALL Report, except to ensure that the material presented in the LRA was applicable, and to verify that the applicant had identified the appropriate programs as described and evaluated in the GALL Report. The staff evaluated those aging management issues recommended for further evaluation in the GALL Report. The staff also reviewed aging management information submitted by the applicant that was different from that in the GALL Report or was not addressed in the GALL Report. Finally, the staff reviewed the UFSAR Supplement to ensure that it provided an adequate description of the programs credited with managing aging for the auxiliary system components.

In LRA Section 3.3, the applicant provided brief descriptions of the auxiliary systems and summarized the results of its AMR of the auxiliary systems at RNP.

Table 3.3-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.3 that are addressed in the GALL Report.

Table 3.3-1 Staff Evaluation Table for RNP Auxiliary System Components Evaluated in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in spent fuel pool cooling and cleanup	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	not applicable	GALL recommends further evaluation (see Section 3.3.2.2.1 below)
Linings in spent fuel pool cooling and cleanup system; seals and collars in ventilation systems	Hardening, cracking, and loss of strength due to elastomer degradation; loss of material due to wear	Plant specific	System Monitoring Program	Consistent with GALL. GALL recommends further evaluation (see Section 3.3.2.2.2 below)
Components in load handling, CVCS (PWR), and reactor water cleanup and shutdown cooling systems (older BWR)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Time-Limiting Aging Analysis	Consistent with GALL. GALL recommends further evaluation (see Section 3.3.2.2.3 below)
Heat exchangers in reactor water cleanup system (BWR); high pressure pumps in CVCS (PWR)	Crack initiation and growth to SCC or cracking	Plant specific	not applicable	The applicant has determined that this aging effect is not applicable to RNP (see Section 3.3.2.4.4.2 below)

Components in ventilation systems, diesel fuel oil system, and emergency diesel generator systems; external surfaces of carbon steel components	Loss of material due to general, pitting, and crevice corrosion, and MIC	Plant specific	System Monitoring Program, Preventive Maintenance Program, Aboveground Carbon Steel Tank Inspection Program, One-Time Inspection Program	Consistent with GALL (see Section 3.3.2.1 below) GALL recommends further evaluation (see Section 3.3.2.2.5)
Components in RCP oil collect system of fire protection	Loss of material due to galvanic, general, pitting, and crevice corrosion	One-Time Inspection	not applicable	RNP does not have a RCP oil collection system. They have an exemption from this requirement.
Diesel fuel oil tanks in diesel fuel oil system and emergency diesel generator system	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling	Fuel Oil Chemistry and One-Time Inspection	Fuel Oil Chemistry Program, One-Time Inspection Program	Consistent with GALL. GALL recommends further evaluation (see Section 3.3.2.2.7)
Piping, pump casing, and valve body and bonnets in shutdown cooling system (older BWR)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	not applicable	BWR
Heat exchangers in CVCS	Crack initiation and growth to SCC and cyclic loading	Water Chemistry and a plant-specific verification program	Water Chemistry Program, One-Time Inspection Program, Closed Cycle Cooling Water System Program	Consistent with GALL. GALL recommends further evaluation (see Section 3.3.2.2.8 below)
Neutron absorbing sheets in spent fuel storage racks	Reduction of neutron absorbing capacity and loss of material due to general corrosion (boral, boron steel)	Plant specific	not applicable	RNP spent fuel racks do not use boral or boron steel neutron absorbing material.
New fuel rack assembly	Loss of material due to general, pitting, and crevice corrosion	Structures Monitoring	not applicable	The applicant has determined that new fuel rack assembly is not in scope for license renewal.
Spent fuel storage racks and valves in spent fuel pool cooling and cleanup	Crack initiation and growth due to SCC	Water Chemistry	Water Chemistry (for managing pitting and crevice corrosion)	The spent fuel storage racks are scoped under structures and are addressed in Section 3.5.2.4.2 of this SER. The valves in SFPCS (see Section 3.3.2.4.9.2 below)

Neutron absorbing sheets in spent fuel storage racks	Reduction of neutron absorbing capacity due to Boraflex degradation	Boraflex Monitoring	Boraflex Monitoring	These components are scoped under structures and are addressed in Section 3.5.2.4.2 of the SER.
Closure bolting and external surfaces of carbon steel and low-allow steel components	Loss of material due to boric acid	Boric Acid Corrosion	Boric Acid Corrosion Program	Consistent with GALL (see Section 3.3.2.1 below)
Components in or serviced by closed-cycle cooling water system	Loss of material due to general, pitting, and MIC	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water System Program	Consistent with GALL (see Section 3.3.2.1 below)
Cranes including bridge and trolleys and rail system in load handling systems	Loss of material due to general corrosion and wear	Overhead Heavy Load and Light Load Handling Systems	Overhead Heavy Load and Light Load Handling Systems Program	These components are scoped under structures and are addressed in Section 3.5.2.4.2 of this SER.
Components in or serviced by open-cycle cooling water systems	Loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and biofouling; buildup of deposit due to biofouling	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System	Consistent with GALL (see Section 3.3.2.1 below)
Buried piping and fittings	Loss of material due to general, pitting, and crevice corrosion, and MIC	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	Buried Piping and Tanks Surveillance Program or Buried Piping and Tanks Inspection Program	Consistent with GALL with exceptions (see Section 3.3.2.3.4 below) or GALL recommends further evaluation (see Section 3.3.2.2.10 below)
Components in compressed air system	Loss of material due to general and pitting corrosion	Compressed Air Monitoring	Preventive Maintenance Program	Consistent with GALL (see Section 3.3.2.1 below)
Components (doors and barrier penetration seals) and concrete structures in fire protection	Loss of material due to wear; hardening and shrinkage due to weathering	Fire Protection	Fire Protection Program	Exceptions taken to GALL, doors, and concrete structures have been evaluated and are acceptable. Penetration seals consistent with GALL (see Section 3.3.2.3.2)

Components in water-based fire protection	Loss of material due to general, pitting, crevice and galvanic corrosion, MIC, and biofouling	Fire Water System	Fire Water System Program	Consistent with GALL/ISG (see Section 3.3.2.3.3)
Components in diesel fire system	Loss of material due to galvanic, general, pitting, and crevice corrosion	Fire Protection and Fuel Oil Chemistry	Fire Protection Program Fuel Oil Chemistry Program	Consistent with GALL for FP, PM should confirm with Fuel Oil Chemistry Program
Tanks in diesel fuel oil system	Loss of material due to general, pitting, and crevice corrosion	Aboveground Carbon Steel Tanks	Aboveground Carbon Steel Tanks Program, Buried Piping and Tanks Surveillance Program	Consistent with GALL (see Section 3.3.2.1 below)
Closure bolting	Loss of material due to general corrosion; crack initiation and growth due to cyclic loading and SCC	Bolting Integrity	Bolting Integrity Program	Consistent with GALL (see Section 3.3.2.1 below)
Components in contact with sodium pentaborate solution in standby liquid control system (BWR)	Crack initiation and growth due to SCC	Water Chemistry	not applicable	BWR
Components in reactor water cleanup system	Crack initiation and growth due to SCC and IGSCC	Reactor Water Cleanup System Inspection	not applicable	BWR
Components in shutdown cooling system (older BWR)	Crack initiation and growth due to SCC	BWR SCC and Water Chemistry	not applicable	BWR
Components in shutdown cooling system (older BWR)	Loss of material due to pitting and crevice corrosion and MIC	Closed-Cycle Cooling Water System	not applicable	BWR

Components (aluminum bronze, brass, cast iron, cast steel) in open-cycle and closed-cycle cooling water systems, and ultimate heat sink	Loss of material due to selective leaching	Selective Leaching of Materials	Selective Leaching of Materials Program (for components buried or subject to raw water) Closed-Cycle Cooling Water System Program (for CCW and diesel cooling systems)	Selective Leaching of Material Program is consistent with GALL with exceptions (see SER Section 3.0.3.10). Closed-Cycle Cooling Water System Program is consistent with GALL (see Section 3.3.2.1 below)
Fire barriers, walls, ceilings, and floors in fire protection	Concrete cracking and spalling due to freeze-thaw, aggressive chemical attack, and reaction with aggregates; loss of material due to corrosion of embedded steel	Fire Protection and Structures Monitoring	Fire Protection Program and Structures Monitoring	These components are scoped under Structures and are addressed in Section 3.5.2.4.3 of this SER.

The staff's review of the auxiliary systems for the RNP LRA is contained within four sections of this SER. Section 3.3.2.1 is the staff review of components in the auxiliary systems that the applicant indicates are consistent with GALL and do not require further evaluation. Section 3.3.2.2 is the staff review of components in the auxiliary systems that the applicant indicates are consistent with GALL and GALL recommends further evaluation. Section 3.3.2.3 is the staff evaluation of AMPs that are specific to the auxiliary systems group. Section 3.3.2.4 contains an evaluation of the adequacy of aging management for components in each system in the auxiliary systems group and includes an evaluation of components in the auxiliary systems that the applicant indicates are not in GALL.

3.3.2.1 Aging Management Evaluations in the GALL Report That Are Relied On for License Renewal, Which Do Not Require Further Evaluation

For component groups evaluated in GALL for which the applicant has claimed consistency with GALL, and for which GALL does not recommend further evaluation, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation. The staff also sampled component groups to determine whether the applicant had properly identified those component groups in GALL that were not applicable to its plant.

On the basis of this review, the staff has determined that the applicant's basis of managing aging effects associated with auxiliary systems is consistent with GALL.

3.3.2.2 Aging Management Evaluations in the GALL Report That Are Relied On for License Renewal, For Which GALL Recommends Further Evaluation

For component groups evaluated in GALL for which the applicant has claimed consistency with GALL, and for which GALL recommends further evaluation, the staff reviewed the applicant's evaluation to determine whether it adequately addressed the issues for which GALL recommended further evaluation. In addition, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation.

The GALL Report indicates that further evaluation should be performed for the aging effects described in the following sections.

3.3.2.2.1 Loss of Material Due to General, Pitting, and Crevice Corrosion

Loss of material due to general, pitting, and crevice corrosion could occur in the channel head and access cover, tubes, and tubesheets of the heat exchanger in the spent fuel pool cooling and cleanup system, while loss of material due to pitting and crevice corrosion could occur in the filter housing, valve bodies, and nozzles of the ion exchanger in the spent fuel pool cooling and cleanup system. The Water Chemistry Program relies on monitoring and control of reactor water chemistry based on EPRI guidelines TR-105714 for primary water chemistry in PWRs, and TR-102134 for secondary water chemistry in PWRs, to manage the effects of loss of material from general, pitting, or crevice corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause general, pitting, or crevice corrosion. Therefore, verification of the effectiveness of the Chemistry Control Program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage loss of material from general, pitting, and crevice corrosion to verify the effectiveness of the Water Chemistry Program. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

The staff reviewed the applicant's proposed program to ensure that corrosion is not occurring and that the components' intended functions will be maintained during the period of extended operation. If the applicant proposed a one-time inspection of select components at susceptible locations to ensure that corrosion is not occurring, the staff verified that the applicant's selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. The staff also verified that the proposed inspection would be performed using techniques similar to ASME Code and ASTM standards, including visual, ultrasonic, and surface techniques.

In LRA Table 3.3-1, row 1, under the discussion column, the applicant stated that the in-scope components (filters and demineralizers) and material (carbon steel with lining) specified in the GALL Report are not applicable to the RNP spent fuel pool cooling system (SFPCS). For RNP, the applicable in-scope components are limited to SS valves, pipes, fittings, and flow elements in the SFPCS. The applicant credited the Water Chemistry Program for managing the aging effects of loss of material due to pitting and crevice corrosion for these in-scope components. The applicant assumed that oxygen and contaminants are present such that crevice corrosion is possible if low flow conditions exist. The applicant further stated that the GALL Report, Sections VII.E.1 and VII.A.3, notes that effects of crevice and pitting corrosion on SS are not significant in chemically treated borated water. Therefore, the applicant determined that the Water Chemistry Program alone is sufficient to manage the aging mechanisms. During a telephone conversation on June 9, 2003, the applicant clarified that the SFPCS is within the scope of the One-Time Inspection Program as described in LRA B.4.4. The applicant further stated that the One-Time Inspection Program is used to verify the effectiveness of the Water

Chemistry Program. The staff's evaluation of the Water Chemistry Program and the One-Time Inspection Program is discussed in Sections 3.0.3.3 and 3.0.3.9 of this SER.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of the loss of material due to pitting and crevice corrosion for components in the spent fuel cooling system, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.2.2.2 Hardening and Cracking or Loss of Strength Due to Elastomer Degradation or Loss of Material Due to Wear

The GALL Report recommends further evaluation of programs to manage the hardening and cracking due to elastomer degradation of valves in the spent fuel pool cooling and cleanup system. The GALL Report also recommends further evaluation of programs to manage the hardening and loss of strength due to elastomer degradation of the collars and seals of the duct and of the elastomer seals of the filters in the control room area, auxiliary and radwaste area, and primary containment heating and ventilation systems, and of the collars and seals of the duct in the DG building ventilation system. The GALL Report also recommends further evaluation of programs to manage the loss of material due to wear of the collars and seals of the ducts in the ventilation systems. The staff reviewed the applicant's proposed programs to ensure that an adequate program will be in place for the management of these aging effects.

The applicant credited the Systems Monitoring Program to manage aging effects of hardening, cracking, and loss of strength due to elastomer degradation, and loss of material due to wear for flexible collars in a group of systems. However, the staff noted that AMP B.3.17 did not include wear as one of the aging mechanisms of concern. By letter dated February 11, 2003, the staff requested, in RAI 3.3-1, the applicant to clarify the discrepancy between Table 3.3-1, Row Number 2, and AMP B.3.17 regarding the aging effects/mechanisms of concern. In addition, the applicant was requested to provide the frequency of the inspection described in AMP B.3.17 for the applicable elastomer components, including a discussion of the operating history to demonstrate that the applicable aging degradations will be detected prior to the loss of their intended function. The RAI response and the staff's evaluation are documented in Section 3.3.2.5.1 of this SER and is characterized as resolved. The staff finds that the applicant has demonstrated that the Systems Monitoring Program is adequate to detect the hardening and cracking, or loss of strength due to elastomer degradation, or loss of material due to wear for elastomer components in ventilation systems prior to the loss of their intended function.

This GALL/SRP item also addresses the hardening, cracking, and loss of strength due to elastomer degradation in the SFPCS. The applicant stated that the RNP SFPCS does not contain elastomer-lined components, therefore, this item is not applicable to the RNP SFPCS. The staff finds this reasonable and acceptable.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of hardening and cracking, or loss of strength due to elastomer degradation, or loss of material due to wear for components in the applicable auxiliary systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.2.2.3 Cumulative Fatigue Damage

Fatigue is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff reviewed the evaluation of this TLAA in Section 4.3 of this SER, following the guidance in Section 4.3 of the SRP-LR.

For the CVCS, the applicant identified that TLAAs are applicable to the charging pumps lube tanks, excess letdown heat exchanger shell and cover/tubing, flow orifices/elements, regenerative heat exchanger tubing, shell, and cover, seal injection filter, seal return filter, valves, piping, tubing, and fittings. The applicant also identified a TLAA for valves, piping, and fittings in the primary sampling system. The applicant discusses the TLAAs in Section 4.3.1 of the LRA, "Reactor Coolant and Associated System Fatigue." This TLAA is evaluated in Section 4.3 of this SER.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of cumulative fatigue damage for components in the applicable auxiliary systems, as recommended in the GALL Report. On the basis of this finding, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.2.2.4 Crack Initiation and Growth Due to Cracking or Stress-Corrosion Cracking

The GALL Report recommends further evaluation of programs to manage crack initiation and growth due to cracking of the high-pressure pump in the CVCS. The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of this aging effect.

In LRA Table 3.3-1, row 4, the applicant described its bases for excluding the aging effect of cracking due to SSC for the CVCS charging pump. By letter dated February 11, 2003, the staff requested, in RAI 3.3.4-7, the applicant to provide site OE to support its bases for excluding the cracking due to SCC for the subject charging pump.

By letter dated April 28, 2003, the applicant provided its response to the RAI 3.3.4-7. The staff's evaluation of the applicant's response is documented in Section 3.3.2.4.4.2 of this SER, and is characterized as resolved.

On the basis of its review, the staff finds the applicant's bases for excluding the aging effect of cracking due to SSC for the CVCS charging pump reasonable and acceptable because the industry and RNP site OE support and validate that conclusion.

3.3.2.2.5 Loss of Material Due to General, Microbiologically Influenced, Pitting, and Crevice Corrosion

The GALL Report recommends further evaluation of programs to manage the loss of material due to general, pitting, and crevice corrosion of the piping and filter housing and supports in the control room area, the auxiliary and radwaste area, and the primary containment heating and ventilation systems; of the piping of the DG building ventilation system; and of the aboveground piping and fittings, valves, and pumps in the diesel fuel oil system, and of the diesel engine starting air, combustion air intake, and combustion air exhaust subsystems in the emergency diesel generator system. The GALL Report also recommends further evaluation of programs to manage the loss of material due to general, pitting, and crevice corrosion, and MIC of the duct fittings, access doors, closure bolts, equipment frames, and housing of the duct, due to pitting and crevice corrosion of the heating/cooling coils of the air handler heating/cooling, and due to general corrosion of the external surfaces of all carbon steel SCs, including bolting exposed to operating temperatures less than 212 °F in the ventilation systems. The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of these aging effects.

For components in this component/commodity group, the plant-specific Systems Monitoring Program is used, with some exceptions, to manage the applicable aging effects, including loss of material due to general, crevice, and pitting corrosion, and MIC on external surfaces, as well as loss of heat transfer effectiveness from fouling of heat transfer surfaces. The exception involves the external surfaces of aboveground tanks. For these tanks, the Aboveground Carbon Steel Tank Inspection Program is applicable. In addition, the applicant used the Preventive Maintenance Program, which is a plant-specific program, to manage the effects of aging for internal surfaces of components of this component/commodity group. In addition, based on industry OE, the applicant also uses the One-Time Inspection Program to manage the aging effect of loss of material due to general and crevice corrosion for the internal surfaces of carbon steel emergency diesel exhaust silencers (mufflers) in air and gas environments. The Systems Monitoring Program, the Preventive Maintenance Program, the Aboveground Carbon Steel Tank Inspection Program, and the One-Time Inspection Program are evaluated in Sections 3.0.3.11, 3.0.3.12, 3.3.2.3.5, and 3.0.3.9 of this SER, respectively. The staff finds that these programs can effectively manage the corrosion of external surfaces for the above components that are applicable to RNP auxiliary systems. The staff's evaluation of these AMPs is documented in Sections 3.0.3.12 and 3.0.3.9 of this SER, respectively. The staff finds that these programs can effectively manage the identified aging effects for the above components that are applicable to RNP auxiliary systems.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of the loss of material due to general, MIC, pitting, and crevice corrosion for components in the auxiliary systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.2.2.6 Loss of Material Due to General, Galvanic, Pitting, and Crevice Corrosion

The GALL Report recommends further evaluation of programs to manage the loss of material due to general, galvanic, pitting, and crevice corrosion of tanks, piping, valve bodies, and tubing in the RCP oil collection system in fire protection systems. The Fire Protection Program relies on a combination of visual and volumetric examinations in accordance with the guidelines of

10 CFR Part 50, Appendix R and Branch Technical Position 9.5-1 to manage loss of material from corrosion. However, corrosion may occur at locations where water from washdowns may accumulate. Therefore, verification of the effectiveness of the program should be performed to ensure that degradation is not occurring and that the component's intended function will be maintained during the period of extended operation. The staff reviewed the applicant's proposed program to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation. If the applicant proposes a one-time visual inspection of the bottom half of the interior of the tank, the inspection would be performed to ensure that corrosion is not occurring. If corrosion is identified, a volumetric examination would then be conducted on any problematic areas. The results of examinations will be used as a leading indicator of other susceptible components. The staff also agrees that the proposed inspection would be performed using techniques similar to ASME Code and ASTM standards, including visual, ultrasonic, and surface examination techniques.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of the loss of material due to general, galvanic, pitting, and crevice corrosion for components in the auxiliary systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.2.2.7 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion, and Biofouling

The Gall Report recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion, and MIC, and biofouling of the internal surface of tanks in the diesel fuel oil system, and due to general, pitting, crevice corrosion, and MIC of the tanks of the diesel engine fuel oil system in the emergency diesel generator system. The Fuel Oil Chemistry Program relies on monitoring and control of fuel oil contamination in accordance with the guidelines of ASTM Standards D4057, D1796, D2709, and D2276 to manage loss of material due to corrosion or biofouling. Corrosion or biofouling may occur at locations where contaminants accumulate. Verification of the effectiveness of the Fuel Oil Program should be performed to ensure that corrosion/biofouling is not occurring and that the components' intended functions will be maintained during the period of extended operation.

In LRA Table 3.3-1, row 7, the applicant stated that the GALL Report includes only tanks in this group. The RNP AMR included in this group the valves, piping, and fittings in systems connected to the tanks that are subject to the same fuel oil environment and subject to the same aging effects/mechanisms. The applicant credited the Fuel Oil Chemistry Program and One-Time Inspection Program for managing loss of material due to general corrosion, crevice corrosion, pitting corrosion, MIC, and biofouling for the applicable components in the fuel oil systems of the diesel fire pump, dedicated shutdown diesel (DSD), emergency operations facility/technical support (EOF/TSC) security diesel, and emergency diesel systems. The applicant further stated that internal inspection of large fuel oil storage tanks is performed periodically. Internal surfaces are inspected for coating integrity; if coating integrity were found to be compromised, appropriate corrective action would be taken. A one-time inspection of the small, elevated, diesel fire pump fuel oil tank and DG day tanks is not warranted. These small tanks have limited access to the tank internals, making it impractical to clean and perform a meaningful inspection. Also, RNP OE indicates that degradation of these tanks is not occurring. The Fuel Oil Chemistry Program ensures a high quality, noncorrosive, nonbiologically contaminated fuel oil for use at RNP. Periodic measurements of bacteria as well as trending of sample results will be performed. Biofouling was not identified as an aging mechanism; however, the above program would detect biofouling, should it occur, as well as loss of material. The applicant concluded that, based on the above, the Fuel Oil Chemistry Program, supplemented with periodic inspections of large tanks, provides for aging management of fuel oil tank internals consistent with the GALL Report, with exceptions as documented in the description of the program in Appendix B of the LRA. The staff's evaluation of these AMPs is documented in Sections 3.3.2.3.6 and 3.0.3.9 of this SER, respectively. The staff finds that these AMPs can effectively manage the aging effects for the above components that are applicable to RNP auxiliary systems.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of the loss of material due to general, pitting, crevice corrosion, and MIC, and biofouling for components in the applicable auxiliary systems, as recommended in the GALL report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.2.2.8 Crack Initiation and Growth Due to Stress-Corrosion Cracking and Cyclic Loading

Crack initiation and growth due to SCC and cyclic loading could occur in the channel head and access cover, tubesheets, tubes, shell and access cover, and closure bolting of the regenerative heat exchanger, and in the channel head and access cover, tubesheets, and tubes of the letdown heat exchanger in the CVCS. The Water Chemistry Program relies on monitoring and control of water chemistry based on the guidelines of TR-105714 for primary water chemistry to manage the effects of crack initiation and growth due to SCC and cyclic loading. The GALL Report recommends further evaluation to manage crack initiation and growth from SCC and cyclic loading for this system to verify the effectiveness of the Water Chemistry Program. The staff reviewed the applicant's proposed program to ensure that cracking is not occurring and that the component's intended function will be maintained during the period of extended operation. The GALL states that a one-time inspection of select components and susceptible locations is an acceptable method to ensure that crack initiation and growth are not occurring and that the components' intended functions will be maintained during the period of extended operation.

In LRA Table 3.3-1, row 8, the applicant stated that SCC is an applicable aging mechanism for the seal water, excess letdown, and regenerative heat exchangers. The applicant credited the Water Chemistry Program for managing the crack initiation and growth due to SCC in these heat exchangers and the Closed-Cycle Cooling Water System Program for managing the aging effect for heat exchangers cooled by the CCW system. To verify the effectiveness of the Water Chemistry Program in preventing cracking due to SCC, the applicant credited an inspection of small-bore Class 1 piping system and components connected to the RCS under the One-Time Inspection Program in selected locations where degradation would be expected. The applicant stated that management of SCC for this group is consistent with the GALL Report with the exception that the one-time inspection will be used instead of the eddy current testing recommended in the GALL Report. The Water Chemistry Program and the One-Time

Inspection Program are evaluated in Sections 3.0.3.3 and 3.0.3.9 of this SER. The staff finds that these programs can effectively manage the cracking initiation and growth due to SCC for the above components that are applicable to RNP auxiliary systems.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of crack initiation and growth due to SCC and cyclic loading for components in the auxiliary systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that these aging effects will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.2.2.9 Reduction of Neutron-Absorbing Capacity and Loss of Material Due to General Corrosion

Reduction of neutron-absorbing capacity and loss of material (boral or boron steel) due to general corrosion could occur in the neutron-absorbing sheets of the spent fuel storage rack in the spent fuel storage pool. The GALL Report recommends further evaluation of programs to manage these aging effects. The applicant determined that this aging effect/mechanism is not applicable because the RNP spent fuel racks do not use boral or boron steel neutron-absorbing materials. The staff finds this reasonable and acceptable.

3.3.2.2.10 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

Loss of material due to general, pitting, and crevice corrosion, and MIC could occur in the underground piping and fittings in the open-cycle cooling water system (service water system (SWS)) and in the diesel fuel oil system. The Buried Piping and Tanks Inspection Program relies on industry practice, frequency of pipe excavation, and OE to manage the effects of loss of material from general, pitting, and crevice corrosion, and MIC. The staff reviewed the effectiveness of the Buried Piping and Tanks Inspection Program, including its inspection frequency and OE, to ensure that loss of material is not occurring and that the component's intended function will be maintained during the period of extended operation.

For buried piping and tanks in the SWS, together with the valves, piping, and fittings in the primary and demineralized water makeup systems, the applicant credited the Buried Piping and Tanks Inspection Program for monitoring the aging effects of loss of material due to general, pitting, and crevice corrosion, and MIC. The applicant stated, in Table 3.3-1, row 17, that, based on OE, it was determined that periodic inspection of susceptible locations is not necessary. The number of leaks caused by external corrosion in buried pipe have been small and limited to service water piping. The applicant further stated that three leaks have occurred in the north service water header, and were limited to pipe in a section of header that was rerouted for construction of the radwaste building in 1984. The cause of leakage has been identified as construction-related defects in the coating applied to the exterior of the pipe. No leaks have been detected in the undisturbed portion of the service water piping. Therefore, the applicant concluded that additional measures to detect aging effects are not necessary, and that the management of aging effects is consistent with the GALL Report with the exceptions detailed in the program description for AMP B.3.12 (Buried Piping and Tanks Inspection Program) in Appendix B. The AMP B.3.12 is evaluated in Section 3.3.2.3.7 of this SER. The staff finds that the applicant's proposed approach, including performing inspection whenever the buried component within the scope of this program is exposed, can effectively manage the aging effects of the above components that are applicable to RNP auxiliary systems.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of the loss of material due to general, pitting, crevice corrosion, and MIC for components in the auxiliary systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.2.2.11 Conclusions

The staff has reviewed the applicant's evaluation of the issues for which GALL recommends further evaluation for components in the auxiliary systems. On the basis of its review, the staff finds that the applicant has provided sufficient information to demonstrate that the issues for which the GALL recommends further evaluation have been adequately addressed and that there is reasonable assurance that the subject aging effects will be adequately managed for the period of extended operation. In addition, the staff concludes that the applicant's UFSAR Supplement provides an adequate description of the programs credited with managing these aging effects, as required by 10 CFR 54.21(d).

3.3.2.3 Aging Management Programs (System-Specific)

In SER Sections 3.3.2.1 and 3.3.2.2, the staff determined that the applicant's AMRs and associated AMPs will adequately manage component aging in the auxiliary systems. The staff then reviewed specific components in the auxiliary systems to ensure that they were properly evaluated in the applicant's AMR.

To perform its evaluation, the staff reviewed the components listed in LRA Tables 2.3-7 through 2.3-25 to determine whether the applicant had properly identified the applicable AMRs and AMPs needed to adequately manage the aging effects for the components. This portion of the staff review involved identification of the aging effects for each component, ensuring that each aging effect was evaluated using the appropriate AMR in Section 3, and that management of the aging effect was captured in the appropriate AMP. The results of the staff's review are provided below.

The staff also reviewed the UFSAR Supplements for the AMPs credited with managing aging in auxiliary systems components to determine whether the program description adequately describes the program.

The applicant credits 18 AMPs to manage the aging effects associated with components in the auxiliary systems. Eleven of the AMPs are credited to manage aging for components in other system groups (common AMPs) while seven AMPs are credited to manage aging only for auxiliary system components. The staff's evaluation of the common AMPs credited with managing aging in auxiliary system components is provided in Section 3.0.3 of this SER. The common AMPs are listed below:

- Metal Fatigue of Reactor Coolant Pressure Boundary (Fatigue Monitoring Program)—SER Section 3.0.3.1
- ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program—SER Section 3.0.3.2
- Water Chemistry Program—SER Section 3.0.3.3
- Boric Acid Corrosion Program—SER Section 3.0.3.4
- Bolting Integrity Program—SER Section 3.0.3.6
- Open Cycle Cooling Water System Program—SER Section 3.0.3.7
- Closed-Cycle Cooling Water System Program—SER Section 3.0.3.8
- One-Time Inspection Program—SER Section 3.0.3.9
- Selective Leaching of Material Program—SER Section 3.0.3.10
- Systems Monitoring Program—SER Section 3.0.3.11
- Preventive Maintenance Program—SER Section 3.0.3.12

The staff's evaluation of the seven auxiliary system AMPs are provided in the following sections.

3.3.2.3.1 Inspection of Overhead Heavy Load and Light Load Handling Systems Program

3.3.2.3.1.1 Summary of Technical Information in the Application

The applicant's Inspection of Overhead Heavy Load and Light Load Handling Systems Program is discussed in LRA Section B.3.6, "Inspection of Overhead Heavy Load and Light Load Handling Systems Program." The applicant stated that the program is consistent with GALL X1.M23, "Overhead and Light Load (Related to Refueling) Handling Systems," with the exception of enhancements to be made in the administrative controls in order to (1) add the turbine gantry crane as a system requiring walkdown for license renewal purposes and (2) require cranes to be inspected using the attribute inspection checklist for structures.

The applicant states that the Inspection of Overhead Heavy and Light Load Handling Systems Program is credited for aging management of the following crane lifting devices at RNP:

- containment polar crane
- spent fuel cask crane
- turbine gantry crane
- spent fuel bridge crane

The aging effect/mechanism of concern has been identified by the applicant as loss of material due to corrosion.

As part of the OE with the overhead heavy and light load handling systems at RNP, the LRA states that three of the cranes that are in scope for license renewal have been addressed by the Maintenance Rule requirements provided in 10 CFR 50.65 and, therefore, have documented OE. The LRA states that the Maintenance Rule Program demonstrates that testing and monitoring programs have been implemented and have ensured that the SSCs of the cranes are capable of sustaining their rated loads, which is their intended function during the period of extended operation. The applicant noted that many of the systems and components of these cranes perform an intended function with moving parts or with a change of configuration, or subject to replacement based on qualified life, and thus are not within the scope of license renewal or the AMP. The LRA states that the program is primarily concerned with structural components that make up the bridge and trolley.

The LRA states that the cranes are periodically inspected to satisfy the ANSI B30.2 and NUREG-0612 requirements for inspection attributes such as steel member corrosion, damaged members or connections, baseplate or anchor bolt corrosion, damaged or degraded grout pads, structure geometry to include absence of excessive deflection cross section distortion, or member misalignment, missing parts, coat deficiencies, and structural cracking. Inspections are documented on a system walkdown report. The applicant's work management program schedules performance of crane maintenance and corrective actions.

3.3.2.3.1.2 Staff Evaluation

In LRA Section B.3.6, "Inspection of Overhead Heavy Load and Light Load Handling Systems Program," the applicant described its AMP to manage aging in overhead heavy and light load handling systems. The LRA stated that this AMP is consistent with GALL X1.M23, "Overhead and Light Load (Related to Refueling) Handling Systems," with no deviations. The staff confirmed the applicant's claim of consistency during the AMP audit. In addition, for RNP, the staff determined whether the applicant properly applied the GALL program to its facility. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

The applicant did not specifically identify the service class (such as Crane Manufacturers Association of America, Inc. (CMAA) Specification #70 or #74) to which cranes within the scope of license renewal were designed. In RAI B.3.6-1 the staff asked the applicant to provide this information. In its response dated June 13, 2003, the applicant provided the service classifications for the cranes, and the Polar Crane and the Spent Fuel Cask Crane will have low fatigue usage factors at the end of the extended operating period. The staff finds the applicant's response acceptable because the fatigue evaluations, in accordance with the CLB, will remain valid for the period of extended operation.

Section B.3.6 of the LRA states that enhancements will be made in the scope of the program so that the cranes will be inspected using the attribute inspection checklist for structures. In RAI B.3.6-2, the staff asked the applicant to provide a summary of the attribute inspection checklist. In its response dated April 28, 2003, the applicant provided this attribute inspection checklist, which is as follows:

- Steel member and connection corrosion
- Damaged members, or connections (deformation, tears, cracks, broken welds, loose bolts, etc)

- Baseplate or anchor bolt corrosion
- Damaged or degraded gout pads
- Structure geometry to include excessive deflection, cross-section distortion, or member misalignment
- Missing parts (including bolts, nuts, connectors, washers, over slotted holes, etc.)
- Coating Deficiencies

The applicant further stated that the attribute inspection checklist for structures does not explicitly address the subject of wear. However, the existing terminology will be enhanced to include wear in accordance with the GALL terminology. As a result of the above, the applicant stated that the information in the second paragraph of the UFSAR Supplement is modified to read as follows:

> Administrative controls for Inspection of Overhead Heavy Load and Light Load Handling equipment will be enhanced, prior to the period of extended operation to: (1) include requirements for inspecting the turbine gantry crane in addition to the other cranes that require inspection, (2) note that cranes are to be inspected using the attribute inspection checklist for structures, and (3) revise the attribute inspection checklist for structures to include GALL terminology, such as wear.

The staff finds the inspection checklist comprehensive enough to identify incipient degradation and aging mechanisms and, with the enhancement as indicated above, will be in accordance with GALL. Therefore, the staff's concerns related to RAI B.3.6.2 are considered to be resolved.

In RAI B.3.6-3, the staff asked the applicant to clarify whether the effects of wear on the rails will be managed, consistent with GALL XI.M23, and to indicate how rail wear would be managed. In its response dated April 28, 2003, the applicant stated that crane rails will be managed by the Inspection of Overhead Heavy Load and Light Load Handling Systems Program. The applicant further stated that, although wear was not specifically identified as an aging effect, crane rails are addressed as a structural commodity for steel member and connection corrosion, and damaged members or connections (e.g., deformation, tears, cracks, broken welds, loose bolts). Additionally, existing terminology will be enhanced to include GALL terminology, such as wear, as stated earlier.

In response to RAI B.3.6.3, the applicant also stated that only personnel trained and familiar with cranes through education and work experience can perform the inspections. Civil engineering is consulted when observed structural degradation could affect the load bearing capabilities of the crane. Conditions that do not meet the prescribed acceptance criteria are documented and corrective action applied. The staff considers the use of qualified individuals to perform the inspections and the use of the applicant's Corrective Actions Program to resolve conditions that do not meet the acceptance criteria to be appropriate and acceptable.

3.3.2.3.1.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.3.2.3.2 Fire Protection Program

The applicant described its Fire Protection Program in Section B.3.1 of the LRA. The applicant credits this program with managing the aging of fire protection (FP) SCs that are within the scope of license renewal and subject to an AMR. The staff reviewed the Fire Protection Program to determine whether the applicant has demonstrated that the program will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.2.1 Summary of Technical Information in the Application

The LRA states that the Fire Protection Program is consistent with GALL XI.M26, "Fire Protection," with the following exceptions—valve alignment and system status are not formally verified each month. Fire barrier inspections are not performed on the refueling frequency as specified in GALL. The RNP performs detailed inspections semiannually rather than bimonthly as specified by GALL.

For OE, the LRA states that self-assessments and external inspections were reviewed for programmatic deficiencies, and it was found that the Fire Protection Program effectively fulfilled regulatory requirements. Based on the inspections, the applicant states that there is evidence that the Fire Protection Program is not only effective, but also subject to ongoing observation/assessment and continual improvement.

3.3.2.3.2.2 Staff Evaluation

In LRA Section B.3.1, "Fire Protection Program," the applicant described its AMP to manage the aging of components in the Fire Protection Program. The LRA states that this AMP is consistent with GALL XI.M26, "Fire Protection," with exceptions.

Valve alignment and system status are not formally verified each month. The applicant checks valve positions and system status subsequent to any system realignments and as needed to support plant operation. The current procedures/practices are deemed, by the applicant, to be acceptable for the current license period. The applicant did not identify valve alignment issues as significant in their review of OE. On the basis that operating experience has demonstrated this methodology to be effective at ensuring proper value alignment, the staff considers the valve position verification subsequent to system realignments and to support plant operation acceptable.

The applicant has proposed to perform inspections of fire barriers under systems and structures monitoring procedures. The inspections will be performed at a level of scrutiny deemed necessary by the applicant. The inspection interval is based on safety significance, not to exceed 10 years, as compared to the refueling frequency as specified in GALL. Fire barriers are generally concrete or masonry structures, except the portions that are fire barrier penetrations. The aging of the masonry portions of the barrier will be monitored under the Structures Monitoring Program, whereas the fire barrier penetrations are monitored in accordance with the Fire Protection Program with no exceptions.

The applicant provided additional information regarding the inspection of fire barriers in a letter dated June 13, 2003. On the basis that there is specialized training for the inspection of these barriers, the staff considers this exception acceptable.

The applicant takes exception to GALL with regard to the frequency of the aging inspection of fire doors. GALL specifies bimonthly inspections, whereas RNP performs inspections semiannually. In a letter dated June 13, 2003, the applicant clarified their position. The applicant states that the semiannual inspections have been effective since 1980 in ensuring that age-related degradation will be detected and corrected prior to loss of function. Furthermore, the applicant does concede that damage may occur to fire doors (e.g., damaged during use), and that this type of damage would be event-driven and not age related. Based on the OE provided by the applicant and the explanation of possible expected damage, the staff finds this extended inspection duration acceptable.

During the staff's audit conducted from May 9—13, 2003, the staff reviewed the applicant's inspection of fire hoses for the Fire Protection Program. The inspection noted that the inspection of fire hoses is consistent with the guidance provided in the National Fire Protection Association (NFPA) standards, and the staff found this acceptable.

Operating experience has shown that these inspection frequencies are adequate to ensure that the system maintains its function. The staff finds that these frequencies are acceptable based on the applicant's OE.

3.3.2.3.2.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.3.2.3.3 Fire Water System Program

The applicant described its Fire Water System Program in Section B.3.7 of the LRA. The applicant credits this program with managing the aging of selected fire water system components that are within the scope of license renewal and subject to an AMR. The staff reviewed the Fire Water System Program to determine whether the applicant has demonstrated that the program will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.3.1 Summary of Technical Information in the Application

The LRA states that the Fire Water System Program is consistent with GALL XI.M27, "Fire Water System," with one exception. In the flow tests, portions of the FP sprinkler system which are not routinely subject to flow, will either be flowed in accordance with GALL, or as an alternate, the applicant will conduct internal inspections or UT examination of a representative sampling of these systems. Results of these tests will be used to determine if expansion of scope is necessary. Note that full flow testing, or internal inspections, or UT examination are applicable to "dry pipe" portions of sprinkler systems, as they are not susceptible to biofouling.

The LRA describes an enhancement to GALL involving testing of sprinkler heads prior to the end of the current license period, and repeated 10 years into the period of extended operation.

For OE, the LRA identifies corrosion-related failure of fire pump casings due to general corrosion and thinning in the "splash zones." This aging mechanism is managed by periodic replacement of pump casings. No pump casing failures have been documented since the implementation of the program that involves periodic replacement of the pump casings.

The last 5 years of inspections (internal self-assessments and external inspections) identified that the Fire Water System Program was effective in fulfilling regulatory requirements and supporting the operation of RNP.

3.3.2.3.3.2 Staff Evaluation

In LRA Section B.3.7, "Fire Water System Program," the applicant described its AMP to manage the aging of structures in the FP system. The LRA states that this AMP is consistent with GALL XI.M27, "Fire Water System," with one exception. The exception is that, in the flow tests portion of the sprinkler system that are not routinely subjected to flow, the applicant proposed to perform the flow tests in accordance with GALL, or by performing internal inspections or UT examinations. The applicant's proposed exception is consistent with, "Interim Staff Guidance (ISG)-04: Aging Management of Fire Protection Systems for License Renewal," dated December 3, 2003. Staff position 1 from the ISG states the following.

> Therefore, the staff recommends that the applicant perform a baseline pipe wall thickness evaluation of the fire protection piping using a non-intrusive means of evaluating wall thickness, such as volumetric inspection, to detect this aging effect before the current license term expires. The staff also recommends that the applicant perform pipe wall thickness evaluations at plant-specific intervals during the period of extended operation.

The staff has reviewed the deviation and its justification to determine whether the AMP, with the deviation, remains adequate to manage the aging effects for which it is credited. The staff finds this exception acceptable. The above discussion addresses aboveground piping; buried fire water piping is managed by the Buried Piping and Tanks Inspection Program.

In LRA Section B.3.7, "Fire Water System Program," the applicant includes the following enhancement, involving the *Acceptance Criteria* program element. The enhancement involves a program of field service testing of sprinkler heads in accordance with NFPA Standard 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems." RNP will perform an initial test prior to the end of the current license period, and repeated 10 years into the period of extended operation.

During the AMR inspection (June 9–13, 2003), the staff reviewed the applicant's replacement frequency for fire pump casings for the Fire Protection Program (see LRA Table 3.3-2, Item 30). The audit noted that there is an error in the application and the fire pumps do not have casings, rather the vertical shaft pumps used at RNP use bowls for the pressure boundary function. Furthermore, the inspection indicated that these bowls are not replaced on a 10-year cycle, rather the pumps are overhauled on a 10-year cycle. Overhaul does not specifically require replacement of the bowls. The applicant's letter dated September 16, 2003, included a revision of LRA Table 3.3-2, Item 30. This revision corrected the language to reference bowls rather than casings. The September 16, 2003, letter also corrected the discussion to state that the *diesel and motor-driven fire pumps are overhauled on a 10-year cycle, and this overhaul* includes inspection of the bowls. This modifies the statement that the bowls are replaced on a 10-year frequency. The applicant has determined that, based on OE, this frequency is adequate to manage aging-related degradation.

Operating experience has shown that these inspection frequencies are adequate to ensure that the system maintains its function. The staff finds that these frequencies are acceptable based on the applicant's OE.

The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.3.2.3.3.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.3.2.3.4 Buried Piping and Tanks Surveillance Program

3.3.2.3.4.1 Summary of Technical Information in the Application

The applicant discusses its AMP for buried piping and tanks surveillance in LRA Section B.3.8, "Buried Piping and Tanks Surveillance Program." The applicant states that the program is consistent with GALL XI.M28, "Buried Piping and Tanks Surveillance," with certain exceptions as discussed below. The program is credited for aging management of selected components in the fuel oil system at RNP. The aging effect/mechanism of concern is loss of material due to crevice, general, microbiological, and pitting corrosion. This program supports the auxiliary system as shown in Items 17 and 22 of Table 3.3-1. The applicant also has a Buried Piping and Tanks Inspection Program to manage the degradation of these components (see Section 3.3.2.3.7 of this SER).

In its license renewal review, the applicant evaluated the acceptance criteria associated with the cathodic protection system. The cathodic protection system protects the buried fuel oil system piping and the bottoms of the connected, aboveground tanks. Aspects of underground fuel oil system piping relating to coatings and visual inspections are included within the scope of the Buried Piping and Tanks Inspection Program, as shown in LRA Section B.3.12.

As a result of its license renewal review, the applicant enhanced the program to (1) review and update, as necessary, cathodic protection procedures to ensure consistency with National Association of Corrosion Engineers (NACE) Standard RP-0169, 1996, and (2) install pressure taps and perform leak testing on the underground fuel oil piping from Unit 1 to the Unit 2 diesel fuel oil storage tank, and the underground piping from the diesel fuel oil storage tank to each emergency diesel generator day tank in the RAB.

The applicant reported that in a 1991 NRC inspection, the NRC determined that the cathodic protection system was known to have been operating outside of its original specification. The NRC found that only about 7 years of cathodic protection could be assured following the system's installation in 1981. Degradation of the cathodic protection system in 1988 appeared to have been caused by installation of concrete in the yard. Closure of this concern was based on an inspection of emergency diesel generator fuel oil underground piping that demonstrated the piping coating was intact with no detectable piping degradation. The applicant concluded from this sample that the underground fuel oil piping had not degraded by galvanic corrosion. Additionally, the applicant upgraded the cathodic protection system hardware and established base line operating parameters. In the NRC inspection report, the NRC found that the applicant demonstrated a good knowledge level of the system operation and design. The NRC inspector concluded that the applicant had accomplished appropriate actions to verify the integrity of the underground fuel oil piping and had upgraded the cathodic protection system to an operable status. The net effect of the NRC's inspection was that the applicant placed an increased emphasis on operation of the cathodic protection system.

In 1996 and 2001, the applicant assessed anomalies in data recorded during the monitoring of the cathodic protection system. The assessments recommended corrective action be taken to repair the system. Nevertheless, the applicant concluded that the as-found condition for substantial portions of the buried fuel piping indicated they had some level of cathodic protection prior to system repairs. The applicant stated that its evaluations demonstrate that identification of abnormal conditions is occurring as planned.

The applicant stated that its Buried Piping and Tanks Surveillance Program differs from GALL XI.M28 in the following areas:

(1) The program uses the guidance in NACE RP-01-69-76 in lieu of the 1996 standard. The above-mentioned enhancement to review and update, as necessary, cathodic protection procedures to ensure consistency with NACE Standard RP-0169, 1996, will address this exception.

(2) There are no buried tanks in this program. The cathodic protection system protects buried fuel oil system piping and the external surfaces of fuel oil system tank bottom in contact with the ground.

(3) Aspects of underground fuel oil system piping relating to coatings and inspections are included within the scope of the Buried Piping and Tanks Inspection Program in lieu of the surveillance program.

(4) No documentation of initial coating conductance is available. In-situ measurement of coating conductance is not considered prudent due to the potential to cause coating damage during excavation and measurement, changing the local soil electrolytic conditions, or stressing the coatings due to changes in the local conditions of the supporting soil.

(5) The Buried Piping and Tanks Inspection Program, in lieu of this program, is used to determine the condition of pipe coatings when piping is exposed for any reason.

The applicant stated that the exceptions involving the NACE standard will be addressed by the enhancement planned for this program. The fact that there are no buried tanks has no effect on the capability of the program to detect and manage aging effects. When considered together with the planned activities under the Buried Piping and Tanks Inspection Program, the exceptions involving buried piping coatings and inspections will be adequately addressed by the combined activities of the surveillance and inspection programs. The GALL Report recommends one of the two programs to manage aging of buried piping and tanks; RNP implements both. The Buried Piping and Tanks Inspection Program addresses activities related to visual inspection of buried components. Additional assurance of coating integrity can be inferred by using cathodic protection current measurements. Also, the need for periodic inspections of buried components is reduced by the protection afforded by the impressed current cathodic protection system. Thus, the preventive measures of cathodic protection provided under the Buried Piping and Tanks Surveillance Program and the detection measures provided under the Buried Piping and Tanks Inspection Program provide added assurance that aging effects for buried fuel oil piping and tank bottoms will be adequately managed.

3.3.2.3.4.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.3.8 to ensure that the aging effects caused by loss of material will be adequately managed so that the intended functions of affected buried pipes and tanks will be maintained consistent with the CLB throughout the period of extended operation. The staff confirmed the applicant's claim of consistency during the AMP audit. In addition, for RNP, the staff determined whether the applicant properly applied the GALL program to its facility.

The 10 program attributes in GALL XI.M28 provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage aging effects due to corrosion in the buried piping. Although the applicant did not provide the program attribute descriptions in LRA Section B.3.8, the applicant has stated that the program attributes are consistent with those specified in GALL XI.M28. The applicant retains the program description on record at RNP.

The staff has inspected the program onsite at RNP for acceptability and compared the program's 10 attributes to the 10 attributes described in GALL XI.M28. Inspections of LRA scoping analyses, AMRs, and AMPs are a normal part of the agency's process for reviewing LRAs. Furthermore, the staff has reviewed the enhancements to determine whether the program remains adequate to manage the aging effects for which it is credited, and reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program. In letters dated April 28, and June 13, 2003, the applicant responded to the staff's RAI. The staff's RAI and the applicant's responses are discussed as follows.

In LRA B.3.8, the applicant stated that the Buried Piping and Tanks Surveillance Program is credited for aging management of selected components in the fuel oil system. In RAI B.3.8-1, the staff asked the applicant to provide a list of specific buried pipes and components that are covered in this program.

In its response to RAI B.3.8-1, the applicant stated that the fuel oil pipes that are covered under LRA B.3.8 include the following pipe lines—1½-FO-36, 2-FO-21, 2-FO-58A, and 2-FO-58B. These line numbers represent carbon steel fuel oil pipe and fittings that are buried in soil or in contact with standing water. The pipes connect the Unit 1 internal combustion turbine tanks to the DSD fuel oil storage tank. They also connect the outside diesel fuel oil storage tank to the emergency diesel generator day tanks. The bottoms of these tanks are protected from the loss of material due to corrosion by the cathodic protection system. Yanks protected by the cathodic protection system are only the tanks that are in contact with the ground. It should be noted that the aboveground portion of the fuel oil tanks are discussed in LRA B.3.9, "Aboveground Carbon Steel Tanks Program," which is evaluated in Section 3.3.2.3.5 of this SER.

The staff finds the applicant's response to RAI B.3.8-1 acceptable because the components covered in the Buried Piping and Tanks Surveillance Program are consistent with the commodity group in GALL 2.3.

In LRA B.3.8, the applicant stated that the program elements will be enhanced to review and update cathodic protection procedures and to install pressure taps and perform leak testing on the underground fuel oil piping. In RAI B.3.8-2, the staff asked the applicant to (a) discuss the documentation of these enhancements (when will these enhancements be implemented and how can the NRC ensure the enhancements will be implemented according to the LRA) and (b) discuss the frequency of leak testing and why the leak testing is specified for the diesel fuel oil piping but not other buried piping.

In its response to RAI B.3.8-2a, the applicant stated that LRA UFSAR Supplement, Appendix A, Subsection A.3.1.16, documents the commitment regarding implementation of these enhancements. The staff has confirmed the applicant's documentation of its commitment as shown in this safety evaluation below.

In its response to RAI B.3.8-2b, the applicant stated that currently, fuel oil piping leak-testing is performed every 2 years. This testing is an enhancement to the program since the pressure taps for the piping from the diesel fuel oil storage tank to the day tanks had not yet been installed at the time of the LRA submittal. No leakage has been found in the underground piping from the Unit 1 fuel oil storage tanks to Unit 2 tanks. The applicant stated that based on this OE 2 years is considered a reasonable frequency for the leak test. Leak testing is specified for the diesel fuel oil piping based on environmental concerns. The applicant stated that the leak test is not needed for the other buried piping in the scope of the inspection program discussed in LRA Section B.3.12, because the other piping are in (1) the moderate pressure SWS which has a high flow rate of water, (2) the site fire protection system which is maintained at operating pressure and monitored while in standby conditions, or (3) the DSD, which is a closed coolant system and fluid inventory is monitored periodically.

The staff finds the applicant's response to RAI B.3.8-2 acceptable because the applicant's commitment to enhance the surveillance program is documented in the UFSAR and the leakage testing is an enhancement to the program, which is consistent with the GALL XI.M28.

In LRA B.3.8, the applicant has taken several exceptions to GALL XI.M28. The applicant stated that it uses the guidance in NACE RP-0169-76 in lieu of NACE RP-0169-96, as recommended in GALL XI.M28. The applicant stated that it will perform enhancements to review and update, as necessary, cathodic protection procedures to ensure consistency with the 1996 NACE standards. In RAI B.3.8-3, the staff asked the applicant to show that the 1976 standards and proposed enhancements satisfy the NACE 1996 standards and NACE Standard RP-0285-95 that are recommended in GALL XI.M28.

In its response to RAI B.3.8-3, the applicant stated that there are no buried tanks within this program. Thus, NACE Standard RP-0285-95, Corrosion Control of Underground Storage Tank Systems by Cathodic Protection, is not applicable to this program. The RNP cathodic protection system protects buried fuel oil system piping and the external bottom surface of fuel oil tanks that are in contact with the ground. The planned enhancements to the program will assure consistency with the GALL guidelines regarding NACE Standard RP-0169-96 to the extent that this is possible with an existing cathodic protection system.

The staff finds the applicant's response to RAI B.3.8-3 acceptable because the applicant will review and update its cathodic protection procedures to ensure consistency with GALL XI.M28 and NACE standards. The staff also finds that there are no buried tanks within this program, therefore, NACE Standard RP-0285-95 is not applicable.

GALL XI.M28 recommends that the coating conductance versus time, or the current requirement versus time, be monitored to provide an indication of the coating condition and effectiveness of the cathodic protection system when compared to predetermined values. In LRA B.3.8, the applicant stated that the in-situ measurement of coating conductance is not considered prudent due to the potential to cause coating damage. The applicant also stated that it has no documentation of initial coating conductance. In RAI B.3.8-4, the staff asked the applicant to provide parameters that will be monitored to assure the integrity of the coating on the buried pipe.

In its response to RAI B.3.8-4, the applicant stated that as noted in its response to RAI B.3.12-3, the integrity of the coating on buried piping was established based on excavation and inspection in the early 1990s. In-situ measurement of coating conductance is not considered prudent because it can increase the potential for coating damage during excavation and measurement, and increase the potential for changing the local soil electrolytic conditions, thereby stressing the coatings.

The applicant monitors on a monthly basis rectifier output levels of voltage and amperage for technical comparison of load changes. The applicant maintains the cathodic protection system rectifiers by inspecting and cleaning. The applicant also performs troubleshooting of unexpected changes. Based on site experience, anomalies due to piping configuration changes and other physical damage of installed protection equipment are most often responsible for the changes in output values. Therefore, it is possible to conclude that changes in rectifier settings are due to damaged equipment and not due to coating degradation. If no physical damage or configuration changes are found (and changes to the rectifier settings are needed), the onset of potentially adverse coating degradation may be occurring. As demonstrated by site experience, an investigation would follow to determine the best course of action. The applicant stated that PM is performed annually and determines the pipe-to-soil potential at each anode. This procedure is based on the criteria in RG 1.137, Section C.2.h. An independent assessment of this procedure has been performed using NACE RP-01-69 (1992 revision) as a basis for evaluating the cathodic protection system.

The staff finds the applicant's response to RAI B.3.8-4 acceptable because the applicant will perform PM annually and determine the pipe-to-soil potential at each anode. This parameter will provide an early indication of potential degradation of the protective coating. The staff finds that the applicant's actions are consistent with GALL XI.M28 and NRC RG 1.137.

In RAI B.3.8-5, the staff asked the applicant to describe the cathodic protection system installed and coating material used on the buried piping. In its response to RAI B.3.8-5, the applicant stated that the cathodic protection system in the RNP Units 1 and 2 was installed to protect the light fuel oil piping and storage tanks from galvanic corrosion caused by interaction between soil and piping/tanks. Each unit has its own rectifier that incorporates an impressed current system. Each rectifier serves 21 anodes, which induce electron flow to the surrounding structures/piping system. The rectifiers are 240/80 volt AC to DC, air cooled, pad mounted, DC tap changing, with a DC ammeter and voltmeter. The anodes are 1-1/2-inch diameter with a 2-inch-diameter enlarged end for lead wire attachment. Each anode is 60-inches long with a type CD Durichlor 51 high silicon chromium cast iron, prepackaged within an 8-inch diameter by 84-inch long canister, with 10 feet of #8 American Wire Gage stranded copper-type high molecular weight polyethylene (HMWPE) lead wire. The supply cable from the rectifier to the anodes, and return cable from the piping to the rectifier, is #2 American Wire Gage stranded copper-type HMWPE lead wire. The HMWPE insulation for the lead wire and supply wire is approved for direct burial.

The cathodic protection system supply cable has been installed in a polyvinylchloride (PVC) conduit at an approximate depth of 24-inches below grade (i.e., 24 inches below the base of the concrete slab). The PVC is encased in a 4-inch concrete protection barrier from anode to anode. This barrier is for protection against future excavations. A 10-inch diameter concrete anode box with a cast iron traffic-rated lid is utilized at each anode location for access to the anode splices. The negative terminal of a rectifier is connected to the piping system being protected, and the positive terminal is connected to the strategically located anodes. The locations and installation are in accordance with the recommended practices in Section 8 of the NACE Standard RP-01-69 (1983 revision). Electrical current flow can be adjusted by changing the rectifier output voltage. Current flow to each anode has a maximum current draw of 1 amp.

The cathodic protection system protects piping or vessels in contact with the soil (i.e., the 6-inch pipe from the Unit 1 area to the diesel fuel oil storage tank, the bottom of the diesel fuel oil storage tank, the 2-inch piping from the diesel fuel oil storage tank to the emergency diesel generator day tanks, and the 1-1/2-inch and the 2-inch piping to the auxiliary boilers). Plant personnel monitor and test the cathodic protection system and adjust the rectifier current and voltage, as necessary, to provide adequate protection to the fuel oil system.

The staff finds the applicant's response to RAI B.3.8-5 acceptable because the cathodic protection system in RNP is installed in accordance with NACE standards and, therefore, is consistent with GALL XI.M28.

In RAI B.3.8-6, the staff asked the applicant to (a) discuss the condition of all buried pipes and their coatings that are covered in this program, (b) provide data to show that the cathodic protection system installed on the buried pipes will maintain its integrity and intended function during the extended period of operation, and (c) discuss what controls are in place to allow the cathodic protection system to operate beyond its effective period (e.g., 7 years).

In its response to RAI B.3.8-6a, the applicant stated that the cathodic protection system is designed to protect the buried fuel oil piping, bottoms of the diesel fuel oil storage tank and the three Unit 1 internal combustion turbine fuel oil tanks, and the Unit 1 vertical lighting oil tank. The underground piping in the scope of this program is identified in the RNP response to RAI B.3.8 -1. Also, as noted in the RNP response to RAI B.3.12-3, NRC Inspection Report 50-261/91-21 discussed the inspection results of the emergency diesel generator fuel oil underground piping on March 27 and May 20, 1992. The piping examination demonstrated the piping coating was intact with no detectable piping degradation.

In its response to RAI B.3.8-6b, the applicant stated that the program described in LRA Section B.3.8 consists of a cathodic protection system, which is a subsystem of the emergency diesel generators. This subsystem is completely separate from the emergency diesel generator and is not in scope of license renewal, and as such, it performs no license renewal intended function. However, it is a system intended to protect the buried fuel oil piping from galvanic corrosion. The system is designed and installed in accordance with NACE standards, is operated, monitored, and maintained by procedure, and has a site history of making improvements. This provides assurance that it will operate throughout the extended period of operation.

In its response to RAI B.3.8-6c, the applicant stated that currently it monitors rectifier output levels monthly. The monitoring procedure provides the method necessary to maintain the cathodic protection system rectifiers by inspecting the output voltage and amperage for technical comparison of load changes, and by cleaning to prevent rectifier damage. Another procedure performed annually determines pipe-to-soil potential. This procedure is based on the criteria in RG 1.137, Section C.2.h. An independent assessment of this procedure has been performed using the NACE Standard RP-01-69 (1992 revision) as a basis for evaluating the cathodic protection system. Acceptance criteria are consistent with the NACE standard for pipe-to-soil potential measurements.

The staff finds the applicant's response to RAI B.3.8-6 acceptable because the applicant has shown that its cathodic protection system is maintained consistent with NACE standards and GALL XI.M28.

In LRA B.3.8, the applicant stated that it completed a hardware upgrade of the cathodic protection system and established base line operating parameters. In RAI B.3.8-7, the staff asked the applicant to (a) discuss in detail the hardware upgrade and for which piping (i.e., whether the hardware upgrades satisfy the NACE standards) and (b) describe the base line operating parameters (i.e., whether any of the operating parameters have been examined periodically and compared to the base line to determine the effectiveness of the cathodic protection system).

In its response to RAI B.3.8-7a, the applicant stated that these hardware upgrades were completed in 1992 and were performed in response to the NRC finding as discussed in its response to RAI B.3.12-4. Additionally, the applicant's response to RAI B.3.8-5 includes a general description of the current cathodic protection system. The upgrades included replacement of 20 anodes, including the addition of one anode and the installation of a new positive cable run in conduit.

The buried cable is in a PVC conduit encased in a 4-inch concrete barrier for protection. The cable installation is 24-inches below the bottom of the concrete slab. A 10-inch diameter concrete anode box with cast iron traffic rated lid is installed at each anode, existing anodes were abandoned in place and replacement locations were selected based on vendor recommendations and specifications. Work performed on the cathodic protection system was done in accordance with vendor specifications, which were developed in accordance with recommended practices in Section 8 of the NACE Standard RP-01-69 (1983 revision). The system design and performance was assessed in 1996 and 2001 by an independent company. In 2001, the criteria used to determine the system's effectiveness were based on NACE Standard RP-01-69 (1992 revision). The assessment of the annual PM that determines pipe-to-soil potential is discussed in more detail in the RNP response to RAI B.3.8-4.

In its response to RAI B.3.8-7b, the applicant stated that the surveillance program with enhancements is consistent with the GALL program and identifies any differences as exceptions. The baseline parameters and regular monitoring are described in the RNP response to RAI B.3.8-4. The NACE standards identified in GALL and the parameters described in GALL provide for periodic monitoring to determine effectiveness.

The staff finds the applicant's response to RAI B.3.8-7 acceptable because the applicant has shown that its surveillance program is consistent with GALL XI.M28. In addition, the program has been upgraded in accordance with the NACE standards.

In RAI B.3.8-8, the staff asked the applicant to discuss whether there are other measures that could detect system leaks before the leakage challenges the intended function of the system if the leakage in the buried pipes is not detected by inspection via excavation. In its response to RAI B.3.8-8, the applicant stated that as discussed in its response to RAI B.3.8-2b, planned enhancements include the performance of pressure testing for leakage. The pressure taps were recently installed during RFO-21 in 2002. These enhancements support the confirmation process and can be used to detect leakage in the underground pipe. Currently, leak testing of underground piping from the diesel fuel oil storage tank to the RAB is performed in accordance with an RNP surveillance procedure, which meets the requirements of the ASME Code, Section

XI, Table IWD-2500-1, Item D2.10, and 10 CFR 50.55a(g).

The staff finds the applicant's response to RAI B.3.8-8 acceptable because the applicant will perform periodic pressure tests on buried pipes to monitor potential leakage.

In LRA B.3.8, the applicant stated that the combined activities in this program and Buried Piping and Tanks Inspection Program in LRA Section B.3.12 will manage aging effects on buried piping and tanks. However, the Buried Piping and Tanks Inspection Program is credited to manage the aging effect of loss of material due to galvanic corrosion (corrosion caused by dissimilar metal contacts), whereas the program in Section B.3.8 does not. In RAI B.3.8-9, the staff asked the applicant to clarify why galvanic corrosion is not included in LRA B.3.8. In its response to RAI B.3.8-9, the applicant stated that differences between activities in the surveillance program and inspection program are discussed further in the RNP response to RAI B.3.12-1. As noted in LRA B.3.8, galvanic corrosion is not an applicable aging effect for the components included in the Buried Piping and Tanks Surveillance Program. Also, as stated in LRA B.3.8, the surveillance program applies only to the fuel oil system. Buried components of the fuel oil system are the same material, therefore, galvanic corrosion is not applicable.

The staff finds the applicant's response to RAI B.3.8-9 acceptable because the applicant has clarified that the buried components in the fuel oil system have the same material, therefore, galvanic corrosion (i.e., corrosion between dissimilar metals) is not applicable to the Buried Piping and Tanks Surveillance Program.

3.3.2.3.4.3 UFSAR Supplement

In Section A.3.1.16 of the LRA, the applicant provides a UFSAR Supplement summary for the Buried Piping and Tanks Surveillance Program which manages the aging effect of loss of material for buried portions of the fuel oil system and bottoms of aboveground fuel oil tanks. There are no buried tanks within this program. The program includes an impressed current, cathodic protection system. Preventive measures to mitigate corrosion by protecting the external surface of buried piping and components are performed under a different AMP, the Buried Piping and Tanks Inspection Program. The Buried Piping and Tanks Surveillance Program includes surveillance and monitoring of the cathodic protection system based on the guidance of NACE-RP-0169-76. Prior to the period of extended operation, the applicant will (1) perform a review to ascertain the need to update, as necessary, administrative controls to ensure consistency with NACE Standard RP-0169-96 regarding acceptance criteria for the cathodic protection system, and (2) incorporate additional leak testing provisions for underground piping.

The staff finds that the summary in the UFSAR Supplement is consistent with Section B.3.8, "Buried Piping and Tanks Surveillance Program," and is, therefore, acceptable.

3.3.2.3.4.4 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.3.2.3.5 Aboveground Carbon Steel Tanks Program

3.3.2.3.5.1 Summary of Technical Information in the Application

The applicant describes its AMP for aboveground carbon steel tanks in Section B.3.9 of the LRA. The applicant states that the program is consistent with GALL XI.M29, "Above Ground Carbon Steel Tanks." The program is credited for aging management of exterior surfaces of tanks in the fuel oil system at RNP. The aging effect/mechanism of concern is loss of material due to general corrosion.

As a result of its LR review, the applicant will enhance the program to assure that the external surfaces of the fuel oil tanks are inspected periodically and to include, in the administrative controls for the program, a section specifically addressing corrective actions.

The applicant experienced corrosion on a Unit 1 internal combustion turbine fuel oil tank which resulted in a loss of diesel fuel. The applicant concluded that the failure to detect the leakage was due to inadequate inspection and cleaning of the internal bottom of the tank. The frequency at which past tank inspections had been performed could not be determined. Had the tanks been receiving inspections on an on-going basis, maintenance activities would have identified the potential for a leak. The tanks are now scheduled for inspections (external) on a 5 year cycle. The leak was caused by pitting on the inside surface of the tank bottom. Therefore, this OE is applicable to internal tank corrosion. The applicant stated that corrosion of this type would be minimized by the Fuel Oil Chemistry Program, as opposed to the Aboveground Carbon Steel Tanks Program.

The applicant states that its Aboveground Carbon Steel Tanks Program differs from GALL XI.M29 with respect to the following exception. Thickness measurements are not performed on tank bottoms to detect exterior corrosion because the tanks are protected from corrosion by the cathodic protection system and the tanks are located on a layer of oily sand. The applicant states that the proposed use of cathodic protection and the oily sand used in the tank foundation provide better protection against external corrosion of the tank bottoms than thickness measurement of tank bottoms.

3.3.2.3.5.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.3.9 to ensure that the aging effects caused by corrosion will be adequately managed so that the intended functions of affected aboveground carbon steel tanks will be maintained consistent with the CLB throughout the period of extended operation. The staff confirmed the applicant's claim of consistency during the AMP audit. In addition, for RNP, the staff determined whether the applicant properly applied the GALL program to its facility.

The 10 program attributes in GALL XI.M29 provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage aging effects due to corrosion in the aboveground tanks. Although the applicant did not provide the program attributes in LRA Section B.3.9, the applicant has stated that the program attributes are consistent with those specified in GALL XI.M29. The applicant retains the program description on record at RNP.

The staff has inspected the program onsite at RNP for acceptability and compared the program's 10 attributes to the 10 attributes described in GALL XI.M29. Inspections of LRA scoping analyses, AMRs, and AMPs are a normal part of the agency's process for reviewing LRAs. Furthermore, the staff has reviewed the enhancements and exceptions to determine whether the program remains adequate to manage the aging effects for which it is credited, and reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program. In letters dated April 28, and June 13, 2003, the applicant responded to the staff's RAI. The staff's RAI and the applicant's responses are discussed as follows.

In RAI B.3.9-1, the staff asked the applicant to discuss the components covered under the program. In its response to RAI B.3.9-1, the applicant stated that the components managed under this program include diesel fire pump fuel oil tank and oil storage tank vent filter; DSD fuel oil day tank and fuel oil tank; emergency diesel generator day tank vent filters, fuel oil day tanks, and fuel oil storage tank; emergency operating facility diesel generator fuel oil day tank; and Unit 1 internal combustion turbine tanks. The staff finds the applicant's response to RAI B.3.9-1 acceptable because the components that are covered under the program are consistent with the commodity group in GALL 2.3.

In LRA Section B.3.9, the applicant described an OE in which a loss of diesel fuel from the Unit 1 turbine fuel oil tank was detected as discussed above. The root cause was attributed to pitting corrosion on the inside surface of the tank. In RAI B.3.9-2, the staff requested the applicant to (a) provide details of the Unit 1 turbine fuel oil tank leak event (for example, discuss the root cause of the pitting corrosion inside the tank), and (b) discuss whether there are other defense-in-depth measures that would detect the leak and alert the operator to take corrective actions before the leakage challenges the intended function of the system. The staff also asked the applicant to the consequences and safety significance of an undetected turbine fuel oil leak or leak in other fuel oil tanks covered in this program, such as an emergency diesel fuel oil tank leak.

In its response to RAI B.3.9-2a, the applicant stated that the leakage from the bottom of the Unit No.1 lighting oil tank (on LR Drawing G-190204DLR, Sheet 3, it is identified as vertical internal combustion turbine lighting oil tank) was caused from internal corrosion. Consequently this event is associated with LRA Section B.3.10, Fuel Oil Chemistry Program, which includes periodic cleaning and internal inspection of the fuel oil tanks. An impressed current cathodic protection system is used to protect the external surface of tank bottoms as discussed in LRA Section B.3.8, "Buried Piping and Tanks Surveillance Program." No other site-specific OE relevant to the Aboveground Carbon Steel Tanks Program was identified.

The applicant also stated that during a routine fuel tank inspection on Unit No. 1, several pits were discovered in the Unit 1 vertical lighting oil tank floor. Three holes attributed to pitting extended completely through the tank floor. A section of the tank floor was removed to inspect conditions under the tank. The inspection revealed that the tank was positioned directly on the ground, and soil conditions under the tank indicated a loss of diesel fuel from the tank. The three Unit 1 internal combustion turbine tanks are similar tanks. These tanks are administratively isolated from the Unit 1 lighting oil tank. No throughwall pitting was identified in the Unit 1 internal combustion turbine fuel oil tanks, however, one tank experienced partial pitting of the inside surface of the tank bottom and required repair.

The applicant did not identify a root cause of the pitting in the evaluation of the event. However, failure to detect the leak was attributed to an inadequate inspection frequency for the Unit No. 1 tanks. No records of previous inspections were found. Currently, the tanks are scheduled for inspections on a 7-year cycle.

In its response to RAI B.3.9-2b, the applicant stated that the fuel oil tank leak was identified by inspection and was not identified due to a loss of fuel oil inventory. The tank inventory was monitored frequently and no loss of fuel oil occurred that was significant in relation to RNP nuclear safety. Since the leakage did not result in a detectable loss of fuel oil inventory, and the technical specifications governing fuel oil capacity were not violated, this event is not considered safety significant. The Unit 1 internal combustion turbine tanks and the Unit 2 diesel fuel oil storage tank have level instrumentation available for monitoring fuel oil inventory. The Unit 2 diesel fuel oil storage tank and the Unit 1 internal combustion turbine fuel oil tanks are independent of each other, and have low level alarms in the RNP control room. Technical specifications govern the required surveillances that ensure the minimum required inventories are satisfied. The DSD fuel oil tank and dedicated shutdown diesel fuel oil day tank have a local low level alarm on their annunciator panel, which would alert operations of low tank level. The diesel fire pump fuel oil tank level is verified weekly in accordance with surveillance requirements. The diesel day fuel oil day tank for the Emergency Operation Facility/Technical Support Center (EOF/TSC) has a low level alarm on a local annunciator panel that would alert operations to take action to investigate and remedy the condition.

The staff finds the applicant's response to RAI B.3.9-2 acceptable because the applicant clarified the leakage event in the Unit 1 oil tank. The applicant also stated that it inspects and monitors the oil tanks to minimize the consequence of potential leakage event(s). This is consistent with GALL XI.M29.

In LRA Section B.3.9, the applicant stated that the Aboveground Carbon Steel Tank Program is credited for the exterior surface of the carbon steel tanks. In RAI B.3.9-3, the staff asked the applicant to discuss how the integrity of the inside surface of the tank is assured in light of the Unit 1 turbine fuel oil tank leak which was caused by the corrosion in the inside surface, and this program covers only the outside surface of the tank. In its response to RAI B.3.9-3, the applicant stated that the AMP applicable to the inside of the fuel oil tanks is the Fuel Oil Chemistry Program as discussed in LRA Table 3.3-1, Item 7, and LRA Section B.3.10, "Fuel Oil Chemistry Program." The applicant clarified that the bottom of the leaking Unit 1 fuel oil tank was repaired with fiberglass laminate.

The staff finds the applicant's response to RAI B.3.9-3 acceptable because the applicant has indicated that LRA B.3.10, "Fuel Oil Chemistry Program," will manage the aging effect in the inside surface of the oil tanks and the staff has found LRA B.3.10 acceptable as discussed in Section 3.3.2.3.6 of this SER.

In LRA Section B.3.9, the applicant stated that Unit 1 turbine fuel oil tank is scheduled for inspections on a 5-year cycle. However, GALL XI.M29 recommends system walkdowns during each outage. In RAI B.3.9-4, the staff asked the applicant to discuss (a) the inspection frequency for all the above ground carbon steel tanks covered in this program in the extended period of operation and provide the technical basis for the inspection frequency, and (b) the inspection procedures in detail.

In its response to RAI B.3.9-4a, the applicant stated that the 5-year inspection interval discussed in LRA Section B.3.9 is referring to an internal inspection and not the walkdown that satisfies the criteria in this program. The internal cleaning and inspection satisfy the criteria of LRA B.3.10, "Fuel Oil Chemistry Program." The current interval for internal inspections of the Unit No. 1 fuel oil tanks is 7 years as discussed in the applicant's response to RAI B.3.9-2a. The applicant stated that the walkdown of the external, exposed surfaces of carbon steel tanks in the scope of this program during the extended period of operation will satisfy the frequency criteria recommended in the *Monitoring and Trending* criterion of GALL XI.M29.

In its response to RAI.3.9-4b, the applicant stated that the enhanced procedures to perform walkdowns of the external surfaces of the tanks provide qualitative criteria to ensure aging effects are at acceptable levels. The focus of the walkdown is on prevention by ensuring satisfactory condition of the external coatings on the surface of the tanks. For tanks in contact with the ground, the condition of caulking and sealants are observed to prevent water seepage below the tank bottom. If an unsatisfactory condition is identified, it is entered into the Corrective Action Program for evaluation and to determine appropriate corrective actions. The external surfaces of tanks in contact with the ground are also cathodically protected and addressed by LRA Section B.3.8, "Buried Piping and Tanks Surveillance Program," and the applicant's response to RAI B.3.10-10.

The staff finds the applicant's response to RAI B.3.9-4 acceptable because the applicant stated that it performs walkdown inspections to ensure the satisfactory condition of the external coating of the tanks, and the Fuel Oil Chemistry Program will protect the inside surface of the tanks from corrosion. The applicant's approach to tank inspection is consistent with GALL XI.M29.

In LRA Section B.3.9, the applicant stated that its aboveground tanks program takes an exception to the *Detection of Aging Effects* and *Acceptance Criteria* in GALL XI.M29. The applicant will not perform thickness measurements on tank bottoms to detect exterior corrosion as recommended in GALL XI.M29 because the tanks are protected from corrosion by the cathodic protection system and the oily sand that is located underneath of the tanks. In RAI B.3.9-5, the staff asked the applicant to (a) discuss how the oily sand would prevent corrosion of the tank bottom, (i.e., provide OE to show the success of the oily sand application, discuss how the oily sand is situated underneath the tanks, discuss whether periodic inspections will be performed to ensure the presence of the oily sand because the sand could be dispersed by the force of nature), and (b) clarify whether the cathodic protection system has been installed in the aboveground tanks or will be installed at a future date. If the cathodic system is currently in place, the applicant was asked to describe its OE (e.g., condition of the coating) and describe in detail the cathodic protection system that is installed on the tanks.

In its response to RAI B.3.9-5a, the applicant stated that its response to RAI 3.2.1-3 discusses industry practices relating to oily sand. As noted in that response, no credit for the oily sand can be taken to prevent corrosion, and protection using oily sand is not needed since the intrusion of water under the tanks is unlikely and the external surfaces of the tank bottoms are protected by a cathodic protection system. Oily sand was part of the installation of the flat bottom tanks. The tanks are supported on a cylindrical concrete pad that surrounds and contains the sand. The concrete support pads are raised a few inches above the floor of the fuel oil tank containment pads. Along with sealants, this geometry minimizes the chances of seepage of water below the tank. There is no access to the external surface of the tank bottoms, and therefore no periodic inspections are performed. As described in RNP response to RAI B.3.9-2, a section of a tank bottom was inspected during the repair of a Unit 1 fuel oil tank. The presence of water or external corrosion was not identified. The applicant has changed LRA UFSAR Supplement, Section A.3.1.17, to note that oily sand is no longer credited.

In its response to RAI 3.9-5b, the applicant stated that there is no passive cathodic protection inside the tanks and there are no current plans to install such protection. The impressed current cathodic protection system is installed and is discussed in LRA Section B.3.8, "Buried Piping and Tanks Surveillance Program." The cathodic protection system is described in the RNP response to RAI B.3.8-5. The cathodic protection system protects the external surfaces of buried fuel oil piping and the external surfaces of tanks that are in contact with the ground. Aspects of the RNP responses to RAIs B.3.9-2, B.3.9-3, and B.3.9-4 relate to the inside surface of the aboveground tanks. LRA Section B.3.10, "Fuel Oil Chemistry Program," describes the activities that address the aging affects on the inside surfaces of the tank.

The staff finds the applicant's response to RAI B.3.9-5 acceptable because the applicant has shown that the aboveground oil tanks will be maintained satisfactorily under the Aboveground Carbon Steel Tank Program, Fuel Oil Chemistry Program, and Buried Piping and Tanks Surveillance Program. These AMPs will monitor the structural integrity of the tanks covered in LRA B.3.9.

In LRA Section B.3.9, the applicant stated that the program will be enhanced to assure that external surfaces of the fuel oil tanks are inspected periodically and to include corrective actions. In RAI B.3.9-6, the staff asked the applicant to discuss its documentation process of these enhancements to ensure that its commitment is properly recorded. The applicant responded that its commitment is documented in UFSAR Section A.3.1.17.

The staff finds the applicant's response to RAI B.3.9-6 acceptable because the staff has found UFSAR A.3.1.17 acceptable as discussed below.

3.3.2.3.5.3 UFSAR Supplement

In LRA Section A.3.1.17, the applicant provides a UFSAR Supplement summary for the Aboveground Carbon Steel Tanks Program which manages aging effects of loss of material for external surfaces of fuel oil system tanks. The program includes preventive measures to mitigate corrosion by protecting the external surface of carbon steel components, per standard industry practice, with protective paint or coating and with sealant or caulking, at the interface with soil or concrete. Visual inspections during periodic system walkdowns are performed to monitor degradation of the protective paint, coating, caulking, or sealant. For tanks in contact with the ground, the tank sits on a layer of oily sand and a cathodic protection system is provided. These measures assure that degradation is not occurring and that the component intended function will be maintained during the period of extended operation. Prior to the period of extended operation, the administrative controls for the program will be revised to indicate that the external surfaces of the fuel oil tanks are to be inspected periodically and to incorporate corrective action requirements.

The staff finds that the summary in the UFSAR Supplement is consistent with LRA Section B.3.9, "Aboveground Carbon Steel Tanks Program," and is, therefore, acceptable.

3.3.2.3.5.4 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.3.2.3.6 Fuel Oil Chemistry Program

3.3.2.3.6.1 Summary of Technical Information in the Application

The applicant discusses its AMP for fuel oil chemistry in LRA Section B.3.10, "Fuel Oil Chemistry Program." The applicant states that the program is consistent with GALL XI.M30, "Fuel Oil Chemistry," with certain exceptions as discussed below. The Fuel Oil Chemistry Program is credited for managing the following aging effects in selected components in the fuel oil system at RNP—loss of material due to crevice, general, and pitting corrosion in carbon steel and loss of material due to microbiological corrosion in carbon steel, copper alloys, and SS.

As a result of its LR review, the applicant will enhance the program to (1) improve sampling and dewatering of selected fuel oil storage tanks, (2) formalize existing practices for draining and filling the diesel fuel oil storage tank periodically, (3) formalize bacteria testing for fuel oil samples from various tanks, and (4) incorporate quarterly trending of fuel oil chemistry parameters.

The applicant initiated a number of condition reports that resulted in improvements to the Fuel Oil Chemistry Program. One condition report summarizes a 1995 review of industry issues and how it relates to the RNP fuel oil system. The applicant has ensured the delivery of a high quality fuel supply to Unit 1 (and consequently to Unit 2 from Unit 1). The condition report provided a discussion of the measures taken to minimize biological growth in the diesel fuel oil storage tank to reduce the potential for fouling and provided a basis for not requiring biocide addition. As a followup to discovery of several through wall pits in the Unit 1 internal combustion turbine lighting oil tank floor, the other three Unit 1 tanks were inspected, which are within the scope of the LR. One tank showed severe pitting. The other two tanks were found in excellent condition. The degraded tanks were repaired. The Unit 1 tanks are inspected periodically based on tank condition and corrective actions taken. The applicant performed and AMR for all tanks.

Two additional events involved potential contamination of fuel oil. One involved receipt of contaminated fuel oil and resulted in a request for improved controls on carrier oil quality. The other event involved coating degradation and pitting corrosion to the diesel fuel oil storage tank bottom, which has been repaired. The maintenance rule documentation for the system includes laboratory results from oil sample testing. The applicant had not identified adverse bacteria, and results of chemical testing show bulk average oil conditions have always been within specifications.

The applicant also identified several differences between its Fuel Oil Chemistry Program and GALL XI.M30. The applicant determined that the differences result in no significant adverse effects on the ability of the program to manage associated aging effects. The applicant determined that the Fuel Oil Chemistry Program, with the enhancements and exceptions identified above, is consistent with GALL XI.M30.

3.3.2.3.6.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.3.10 to ensure that the aging effects associated with fuel oil chemistry will be adequately managed so that the intended functions of affected SSCs will be maintained consistent with the CLB throughout the period of extended operation. The staff confirmed the applicant's claim of consistency during the AMP audit. In addition, for RNP, the staff determined whether the applicant properly applied the GALL program to its facility.

The 10 program attributes in GALL XI.M30 provide detailed programmatic characteristics and criteria that the staff considers to be necessary to manage aging effects due to fuel oil chemistry in the safety systems and components. Although the applicant did not provide the program attribute descriptions in LRA Section B.3.10, the applicant has stated that the program attributes for the Fuel Oil Chemistry Program are consistent with those specified in GALL XI.M30. The applicant retains the description of the Fuel Oil Chemistry Program on record at RNP.

The staff has inspected the Fuel Oil Chemistry Program on site at RNP for acceptability and compared the program's 10 attributes to the 10 attributes described in GALL XI.M30. Inspections of LRA scoping analyses, AMRs, and AMPs are a normal part of the agency's process for reviewing LRAs. The staff's inspection of the program verifies that the program attributes are acceptable when compared to the corresponding program attributes in GALL XI.M30.

Furthermore, the staff reviewed the enhancements and exceptions and the applicant's justification to determine whether the program remains adequate to manage the aging effects for which it is credited. The staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program. In letters dated April 28, and June 13, 2003, the applicant responded to the staff's RAI. The staff's RAI and the applicant's responses are discussed as follows.

In RAI B.3.10-1, the staff asked the applicant to specify each component and system that will be covered by the Fuel Oil Chemistry Program. In its response to RAI B.3.10-1, the applicant stated that the fuel oil system includes the storage of fuel oil and supply piping systems to the emergency diesel generators (DG), dedicated shutdown diesel, EOF, and diesel fire pump. The specific components are discussed in Item 7 of LRA Table 3.3-1. These components include the diesel fire pump fuel oil tank; dedicated shutdown diesel fuel oil day tank, fuel oil priming pumps, fuel oil pumps, and fuel oil tank; emergency DG fuel oil day tanks, fuel oil duplex filters, fuel oil hand priming pumps, and fuel oil storage tank; emergency operating facility DG fuel oil day tank, fuel oil pump; EOF/TSC main storage tank; flow orifices/elements; fuel oil transfer pumps; Unit 1 internal combustion turbine tanks; and valves, piping, tubing, and fittings. Also, in its response to RAI B.3.8-6 the applicant included vertical lighting oil tank in the LRA scope.

The staff finds the applicant's response to RAI B.3.10-1 acceptable because the applicant has clarified the components that are covered under the Fuel Oil Chemistry Program and these components are consistent with the commodity group of GALL 2.3.

In RAI B.3.10-2, the staff asked the applicant to discuss the enhancements to improve the sampling and dewatering process, specify which storage tanks will be selected and which will not be selected, and discuss the selection criteria. In its response to RAI B.3.10-2, the applicant stated that the basis for the selection of certain tanks was the review of current practices and activities against the criteria found in the GALL program attributes. The specific enhancements are as follows:

- Periodically take a bottom sample from the underground EOF/TSC main storage tank, and analyze it for corrosion products and bacterial growth.

- Two methods currently exist for sampling the fuel oil in the DSD fuel oil tank. Only one would result in removing visible water. Consequently, the enhancement is to ensure that a check for visible water is performed and, if found, removed from the bottom of the tank.

- Formalize current practices for bacteria testing for fuel oil. This should include periodically obtaining bottom samples from the Unit 1 internal combustion turbine tanks, diesel fuel oil storage tank, DSD fuel oil tank, diesel fire pump fuel oil tank, and the EOF/TSC main storage tank.

- Ensure that a check for visible water is performed and, if found, removed from the bottom of the diesel fire pump fuel oil tank.

The staff finds the applicant's response to RAI B.3.10-2 acceptable because the applicant's proposed enhancements to improve the sampling and dewatering process of fuel oil tanks are consistent with GALL XI.M30.

In LRA Section B.3.10, the applicant stated that it will formalize existing practices for draining and filling the diesel fuel oil storage tank and bacteria testing for fuel oil samples from various tanks. In RAI B.3.10-3, the staff asked the applicant to discuss the formalization process and briefly describe the procedures of bacteria testing. In its response to RAI B.3.10-3, the applicant stated that a procedure currently exists for draining and filling the diesel fuel oil storage tank. The applicant will add to this practice by establishing an acceptable frequency of performance. A Betz microbiological test kit has been used for identifying aggressive bacteria. Additional information about bacteria testing can be found in the applicant's response to RAI B.3.10-10 in this safety evaluation below.

The staff finds the applicant's response to RAI B.3.10-3 acceptable because the applicant's formalization process of testing bacteria in fuel oil tanks is consistent with GALL XI.M30.

In LRA Section B.3.10, the applicant discussed several events related to degraded fuel oil tank and fuel oil contamination. The applicant stated that no adverse bacteria had been identified and results of chemical testing show bulk average oil conditions have always been within specifications. In RAI B.3.10-4, the staff asked the applicant to clarify which event(s) described in LRA B.3.10 occurred specifically in RNP. If there was a case of fuel oil contamination in RNP, the applicant should clarify whether it was caused by bacteria. The staff also asked the applicant to discuss the specifications to which the oil conditions were compared and discuss the acceptance criteria of fuel oil.

In its response to RAI B.3.10-4, the applicant stated that the events related to the degraded fuel oil tank did not include contamination from bacteria. In the first event, after fuel oil to the Unit 1 failed to light, the applicant discovered that the Unit 1 lighting fuel oil tank contained contaminants that had resulted in filter clogging. These contaminants were attributed to the fuel oil supplier. This tank is administratively isolated from the internal combustion turbine oil storage tanks. The second event involved coating degradation and pitting corrosion on the internal bottom surface of the diesel fuel oil storage tank. The internal inspection of the diesel fuel oil storage tank performed during RFO-21 identified that the tank floor had a coating failure and some corrosion pitting. The coating on the tank walls, however, was reported to be in good or excellent condition. The applicant analyzed the corrosion products and found that oil at the tank bottom contained water with relatively high chlorine concentrations.

The applicant uses ASTM standards for its fuel oil conditions as discussed in its response to RAI B.3.10-8.

The staff finds the applicant's response to RAI B.3.10-4 acceptable because the applicant has clarified the fuel oil contamination and corrosion events. With regard to the fuel oil conditions, the staff finds that the ASTM standards that the applicant uses are acceptable (see the staff's discussion in RAI B.3.10-8 below).

In LRA Section B.3.10, the applicant identified several exceptions to GALL XI.M30. One of the exceptions is that the Fuel Oil Chemistry Program in RNP is used to manage aging effects on all system components wetted" by fuel oil. This results in additional materials in RNP being in scope beyond those in the GALL Report. In RAI B.3.10-5, the staff asked the applicant to specify each of the additional materials beyond those in the GALL Report. In its response to RAI B.3.10-5, the applicant stated that its response to RAIs B.3.10-1 and B.3.10-10 apply to RAI B.3.10-5. LRA Table 2.3-25 provides additional information on the materials in scope.

The staff reviewed the applicant's responses to RAI B.3.10-1, RAI B.3.10-10, and LRA Table 2.3-25. The staff finds that the additional materials covered in the program are acceptable because they are consistent with the commodity group in GALL 2.3.

In LRA Section B.3.10, the applicant states that it deviates from the one-time inspection in GALL VII.H1, "Diesel Fuel Oil System," which specifies that for the internal surface of a carbon steel tank, the Fuel Oil Chemistry Program be augmented by a one-time inspection in accordance with GALL XI.M32, "One-Time Inspection." The applicant stated that a one-time inspection of a small, elevated, diesel fire pump fuel oil tank and DG day tanks is not warranted because the small tanks have limited access to the tank internals, making it impractical to clean and perform a meaningful inspection. The applicant stated that ultrasonic testing is also considered inappropriate to detect small amounts of pitting in tanks constructed of carbon steel that is measured in units of gauge thickness. The applicant also stated that on the basis of operating history, external tank and structure inspections are considered sufficient to identify degradation in the tank walls.

In RAI B.3.10-6, the staff asked the applicant to (a) discuss how the internal surface integrity of the diesel fire pump fuel oil tank and DG day tanks can be validated if a one-time inspection will not be performed on these tanks, (b) discuss degradation history of all tanks that contain fuel oil that are in the scope of AMR, (c) discuss how the external inspection of the fuel oil tanks can assure the integrity of the inner surface of the tanks, (d) describe the external tank and structural inspection procedures that the applicant will perform and the frequency of such inspections, and (e) if ultrasonic testing is inappropriate to detect degradation in tanks, propose other nondestructive examinations to inspect the inner surface of the tanks.

In its response to RAI B.3.10-6a, the applicant stated that there is no history of failures of the diesel fire pump fuel oil tank and DG day tanks. The DG day tanks are sheltered inside the RAB and not prone to condensation. Fuel oil supplied to the day tanks is taken from a level well above the bottom of the diesel fuel oil storage tank. Water is periodically checked and removed from the emergency diesel day tanks, if found. Consequently, there is no reason to suspect that the integrity of these day tanks is in question.

The diesel fire pump fuel oil tank receives periodic shipments of fuel oil from a local supplier. It is situated outdoors. Currently, fuel oil is sampled periodically, but not from the bottom drain, and there is no periodic requirement for checking for and removing water from the bottom drain. Therefore, the applicant will perform a one-time ultrasonic test or other nondestructive test (or inspection) of the internal surface of the diesel fire pump fuel oil tank in locations most susceptible to corrosion. Testing will be accomplished prior to the beginning of the period of extended operation. If degradation is found, further actions will be evaluated under the Corrective Action Program. The inspection of the diesel fire pump fuel oil tank will be performed under LRA B.4.4, "One-Time Inspection Program." As a result of the above response, the information in LRA Subsection A.3.1.31, "One-Time Inspection Program," is modified to include a one-time ultrasonic, or other nondestructive test, of the diesel fire pump fuel oil tank in locations most susceptible to corrosion.

In its response to RAI B.3.10-6b, -6c, -6d, and -6e, the applicant stated that no failures were identified in fuel oil tanks over a recent 10-year period in RNP, although pitting was detected in the diesel fuel oil storage tank and Unit 1 storage tank. The applicant stated that an external inspection would not be expected to detect minor degradation on the inner surface of the tanks.

However, it will identify minor leakage, which will precede the amount of degradation that would challenge the structural integrity of the tank. Formal inspections (see LRA Sections B.3.9, B.3.15, and B.3.17) will involve a walkdown of the tanks and the area surrounding the tanks. In addition to formal inspections, plant operators on rounds and chemistry personnel obtaining samples are able to identify such leakage. Such leakage would be identified and reported in the Corrective Action Program.

The staff finds the applicant's response to RAI 3.10-6 acceptable because the applicant has committed to perform a one-time inspection of the diesel fire pump fuel oil tank. The DG day tanks are located inside the RAB and not prone to condensation (see the above discussion). The applicant also has shown that it has formal inspections of the fuel oil tanks in RNP. These actions are consistent with GALL XI.M30.

In LRA Section B.3.10, the applicant is taking exception to *Detection of Aging Effects* in GALL XI.M30. The applicant stated that ultrasonic thickness measurements of the bottoms of large storage tanks are not typically performed at RNP unless warranted by the level of coating degradation and corrosion found during inspection. In RAI B.3.10-7, the staff asked the applicant to demonstrate how the thickness of the tank bottom will be verified without ultrasonic measurements and discuss the current procedures in RNP in verifying tank bottom thickness. In its response to RAI B.3.10-7, the applicant stated that its response to RAI B.3.10-10 applies to this question.

The staff finds the applicant's response to RAI B.3.10-10 applicable to RAI B.3.10-7. The staff has found the applicant's response to RAI B.3.10-10 acceptable (see discussion below); therefore, the issue in RAI B.3.10-7 is closed.

In LRA Section B.3.10, the applicant proposed to use alternate standards and acceptance criteria for fuel oil sampling in place of the standards recommended in GALL XI.M30. GALL recommends ASTM Standards D 1796, D 2709, D 4057, and modified D 2276. In RAI B.3.10-8, the staff asked the applicant to show that its alternate standards and acceptance criteria are consistent with the ASTM standards. In its response to RAI B.3.10-8, the applicant stated that in RNP, fuel oil testing is based on ASTM D 1796-97, "Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method," in lieu of ASTM D 2709 for determining water and sediment using a centrifuge approach. The applicant stated that ASTM D 1796-97 is considered a more appropriate test for the fuel oil used at RNP. The testing conducted using ASTM D 1796 gives quantitative results, whereas D 2709 testing gives only pass-fail results; therefore, the D 1796 method gives more descriptive information about the fuel oil condition than the D 2709 method. Both ASTM D 4057 and D 2276 are discussed in the applicant's response to RAI B.3.10-10.

The staff finds the applicant's response to RAI B.3.10-8 acceptable because the applicant will use appropriate ASTM standards to test the fuel oil in RNP which is consistent with GALL XI.M30.

In LRA Section B.3.10, the applicant states that it is taking exception to GALL XI.M30 regarding fuel oil additives. The applicant stated that based on operating history and fuel oil management activities, biocides, biological stabilizers, and corrosion inhibitors are not necessary and are not used in the fuel oil at RNP. GALL XI.M30 states that the quality of fuel oil is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. In RAI B.3.10-9, the staff asked the applicant to clarify how the quality of diesel fuel oil in RNP would be maintained without these additives.

In its response to RAI B.3.10-9, the applicant stated that there is no evidence to suggest that additives would have precluded the degraded oil events. The filter clogging event in the Unit 1 vertical lighting oil tank was caused by debris from a delivery truck and not caused by fuel oil sediments or biological growth. The other event was related to pitting on the bottom of the diesel fuel oil storage tank, and the origin of the aggressive environment for this occurrence was not definitively established. However, the primary corrosion preventive method is the tank's internal coating. The degraded internal coating on the bottom of the tank has since been replaced with an improved coating material. The applicant reviewed condition reports over a recent 10-year period and did not identify any events due to degraded fuel oil. Considering that additives such as biocides and stabilizers have not been used at RNP and that there is no adverse site OE due to degraded fuel oil, the current methods are considered prudent and acceptable. Therefore, no fuel oil additives are considered necessary.

The staff finds the applicant's response to RAI B.3.10-9 acceptable because, although the applicant will not use fuel oil additives, the applicant has certain procedures that would protect the quality of fuel oil as discussed in its response to RAI B.3.10-10. In addition, the applicant has shown that the inside surfaces of the tanks are being protected from corrosion by coating.

In RAI B.3.10-10, the staff asked the applicant to (a) discuss the exceptions to GALL XI.M30 and (b) to demonstrate that its Fuel Oil Chemistry Program is within the CLB.

In its response to RAI B.3.10-10a, the applicant discussed the following exceptions to GALL XI.M30.

Scope of Program — The applicant expanded the scope of the program to manage potential aging effects in more components than the large storage tanks. The focus in the GALL Report is placed on large storage tanks, thereby maintaining the fuel oil quality and its associated container. The internal environments of the components in the fuel oil system are exposed to the quality of fuel oil controlled under this program. Fuel oil from the main storage tank is drawn from a level above the bottom and is representative of the bulk average fluid conditions. Consequently, the components downstream are being managed by the efforts taken to maintain the quality of fuel oil.

Monthly surveillance testing requires a check for water in the emergency diesel generator day tanks. To prevent biological growth, the surveillance requires that water be removed, if found. Quarterly fuel oil samples are taken from the emergency diesel generator day tanks and are tested for water and sediment. The results indicate that fuel oil has remained within specifications for water and sediment.

Preventive Actions — Based on operating history and fuel oil management activities, the applicant stated that biocides, biological stabilizers, and corrosion inhibitors are not necessary and are not used in the fuel oil at RNP. RNP shares fuel oil with Unit 1, which runs an internal combustion turbine that uses significantly more fuel than the Unit 2 emergency diesel generators. This usage results in maintaining a relatively fresh supply of fuel oil. The Unit 1 tanks are used as a repository for fuel oil when the Unit 2 diesel fuel oil storage tanks are drained for periodic inspections and cleaning, as well as periodically refreshing the supply between inspections. This tends to maintain a relatively fresh supply of fuel oil immediately available to the emergency DGs. The dedicated shutdown DG fuel oil storage also receives its fuel oil from Unit 1. To date, site OE supports the viability of this process.

Parameters Monitored/Inspected, Detection of Aging Effects and Acceptance Criteria — The applicant has used alternate standards and acceptance criteria for fuel oil sampling at RNP in place of the ASTM standards recommended in GALL XI.M30. The standards being used at RNP meet or exceed those recommended in GALL. For example, ASTM Standard D 4057 recommended in GALL addresses industry practices for sampling techniques in large fuel oil storage tanks in the petroleum industry. These tanks are significantly larger than the tanks at RNP. NRC Inspection Report 91-21 discussed the methodology used in sampling the diesel fuel oil storage tank at RNP. The method used at RNP of recirculating the oil within the tank was shown to be equivalent to the industry standard to which RNP is committed (ASTM D 270-1975). The NRC was satisfied with the testing results, showing samples drawn using both methods yielded "virtually identical results ...This testing provided justification for the licensee to obtain fuel oil storage tank samples by their existing methodology." ASTM D 2276 covers the test method for determination of particulate contaminants in aviation turbine fuel using a field monitor.

Fuel oil is periodically sampled for suspended particulate using a procedure which is an equivalent laboratory test. The test method is based on ASTM D 5452, which covers the gravimetric determination by filtration of particulate contaminant in a sample of aviation turbine fuel delivered to a laboratory. This test provides equivalent results using a filter with a pore size of 0.8 μm. This pore size (0.8 μm) is identified as the modified test method in GALL for the field test. Equivalency is established because the same filter size is being used as in the suggested modification to the field test method. Additionally, even though the test apparatus is different, its location is in a controlled laboratory environment. It would not be practical to use the laboratory test setup in the field location.

Detection of Aging Effects — Ultrasonic thickness measurements of the bottoms on large storage tanks are not typically performed at RNP unless warranted by the level of coating degradation and corrosion found during inspection. The Fuel Oil Chemistry Program addresses management of the internal surfaces of the components within the fuel oil system. The response to this RAI is based on addressing loss of material due to corrosion mechanisms from inside the tank. The Aboveground Carbon Steel Tanks Program and the Buried Piping and Tanks Surveillance Program address the external surfaces of these carbon steel tanks.

Internal inspection of the diesel fuel oil storage tank is performed periodically based on a maximum 10-year interval. The inspection intervals stated in LRA Sections B.3.9 and B.3.10 for the Unit 1 tanks should have said, "internal inspections of the Unit 1 internal combustion turbine tanks are performed periodically and meet the recommendations in American Petroleum Institute (API) 653." Internal surfaces are inspected for coating integrity. If coating integrity were compromised, additional inspections and appropriate testing would be performed to determine the extent of damage. However, if coatings are intact, then corrosion is not anticipated and further testing would not be necessary.

In recent years, two of the Unit 1 internal combustion turbine tanks and the diesel fuel oil storage tank experienced degradation due to pitting. At that time, ultrasonic testing was done to establish the bottom condition. These tanks have since been repaired. The most recent tank repair was for the diesel fuel oil storage tank, which was repaired in fall 2002 during RFO-21. After the tank was drained, oil sludge was removed and the interior of the tank was pressure washed with high temperature water and citrus degreaser. The bottom of the tank was also sponge jet blasted. Ultrasonic testing measurements were taken at several locations, which established the condition of the tank bottom. No weld repairs of the pitting were required or performed. Belzona Ceramic-R-Metal compound was applied to the tank bottom and on the walls a few inches above the bottom. Provided this coating is shown to remain intact during subsequent tank inspections, corrosion is not anticipated and no further ultrasonic testing would be necessary. The 10-year inspection interval for the diesel fuel oil storage tank has proven to be adequate for identifying aging effects before damage occurs.

Monitoring and Trending — A one-time ultrasonic test or other nondestructive test of the internal surface of the diesel fire pump fuel oil tank will be performed in locations most susceptible to corrosion. Leakage from elevated tanks is readily observable. Throughwall leakage would be detected during operator rounds by external visual inspection of the tank, foundation, and dikes.

In its response to RAI B.3.10-10b, the applicant stated that in accordance with UFSAR Section 1.8.0 and Technical Specification 3.8.3, fuel oil is sampled for specific gravity, water and sediment, viscosity, and cloud point as specified by the API. These specifications are identified in the technical specifications bases. New fuel received for storage in the Unit 1 internal combustion turbine fuel oil storage tanks is verified to meet the analysis limits prior to adding to the Unit 1 internal combustion turbine tanks. Unit 2 diesel fuel oil storage tank is sampled every 31 days. Accumulated water is checked for and removed from each fuel oil storage tank every 31 days.

The enhancements that will be made to support operation during the extended period go beyond the CLB at RNP. One example of such an enhancement is the test for bacteria in the diesel fuel oil storage tank. This test is not a licensing requirement at RNP, but it is good practice. The laboratory uses a standard kit to periodically perform this test, and testing is done to the manufacturer's instructions. Formalizing bacteria testing means to convert these manufacturer's instructions into formal laboratory procedures. The enhancements associated with dewatering tanks are discussed in the applicant's response to RAI B.3.10-2.

The staff finds the applicant's response to RAI B.3.10-10 acceptable because the applicant has provided sufficient technical justification to show that the program, with exceptions and enhancements, will manage adequately the aging effects for which the program is credited.

3.3.2.3.6.3 UFSAR Supplement

In Section A.3.1.18 of the LRA, the applicant provides a UFSAR Supplement summary for the Fuel Oil Chemistry Program which relies on a combination of surveillance and maintenance procedures. The applicant states that monitoring and controlling fuel oil contamination in accordance with the guidelines of ASTM standards, and other activities in accordance with the CLB, maintains the fuel oil quality. Corrosion resulting from exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic inspection and cleaning of tanks.

As a result of the LR, the applicant will enhance administrative controls for the program to (a) improve sampling and dewatering of selected storage tanks, (b) formalize existing practices for draining and filling the diesel fuel oil storage tank periodically, (c) formalize bacteria testing for fuel oil samples from various tanks, (d) incorporate quarterly trending of fuel oil chemistry parameters, and (e) perform a one-time ultrasonic inspection or other nondestructive test of the internal surface of the diesel fire pump fuel oil tank.

The staff finds that the summary in the UFSAR Supplement is consistent with Section B.3.10, "Fuel Oil Chemistry Program," and is, therefore, acceptable.

3.3.2.3.6.4 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.3.2.3.7 Buried Piping and Tanks Inspection Program

3.3.2.3.7.1 Summary of Technical Information in the Application

The applicant discusses its AMP for buried piping and tanks inspection in LRA Section B.3.12, "Buried Piping and Tanks Inspection Program." The applicant states that the AMP is consistent with GALL XI.M34, "Buried Piping and Tanks Inspection." The program is credited for aging management of selected components in systems at RNP. The aging effect/mechanism of concern is loss of material due to crevice, general, microbiological, pitting, and galvanic corrosion. The applicant also has a Buried Piping and Tanks Surveillance Program to manage the degradation of buried fuel oil piping (see Section 3.3.2.3.4 of this SER).

As a result of its LR, the applicant will enhance its program as follows—(1) incorporate a requirement to ensure an appropriate as-found pipe coating and material condition inspection is performed whenever buried piping within the scope of this program is exposed; (2) add precautions to ensure backfill with material that is free of gravel or other sharp or hard material that can damage the coating; (3) add a requirement that coating inspections be performed by qualified personnel to assess coating condition; and (4) add a requirement that a coating engineer should assist in evaluation of any coating degradation noted during the inspection.

The applicant reported that leaks have occurred in the north service water header pipe that was installed in 1984. In July 1995, March 1998, and September 1998, the leaks were identified and repaired. In a root cause evaluation, the applicant made three conclusions. First, the environmental conditions found at the location of the north service water header are not especially harsh. The soil has high resistance, which restricts the current flow and consequent corrosion. Second, the root cause of the March and September 1998 leaks was improper installation of the tapecoat external wrapping. The root cause of the July 1995 leak was damage from misoperation of a backhoe during initial installation of the piping. Third, regarding similar situations/generic implications, other buried pipe on site has not exhibited exterior corrosion such as experienced on the north service water header. The original service water piping has the same type of coating used in the north service water header but has not exhibited a similar tendency to leak. The reason for this is the assumption that the coating, when properly installed and not damaged, effectively prevents external degradation.

The applicant determined that the leaks can be and have been detected on site and that appropriate corrective actions have been taken. Environmental conditions are not severe. If coating fails, there will be ample time to identify and repair leaks before catastrophic failure. Additionally, the number of leaks caused by external corrosion in buried pipe has been small and limited to service water piping. Based on plant OE summarized above, the applicant stated that periodic excavations of buried piping for inspection are not warranted.

The applicant states that its Buried Piping and Tanks Inspection Program differs from GALL XI.M34 in the following exceptions—(1) the program contains no buried tanks, (2) the program includes additional components, (i.e., underground fuel oil system piping), (3) in addition to carbon steel components, buried cast iron piping and fittings are included in this program; and (4) the program includes galvanic corrosion as a potential aging mechanism.

3.3.2.3.7.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B.3.12 to ensure that the aging effects caused by corrosion will be adequately managed so that the intended functions of affected buried pipes will be maintained consistent with the CLB throughout the period of extended operation. The staff confirmed the applicant's claim of consistency during the AMP audit. In addition, for RNP, the staff determined whether the applicant properly applied the GALL program to its facility.

The 10 program attributes in GALL XI.M34 provide detailed programmatic characteristics and criteria that the staff considers necessary to manage aging effects due to corrosion in the buried piping. Although the applicant did not provide the program attribute descriptions in LRA Section B.3.12, the applicant has stated that the program attributes are consistent with those specified in GALL XI.M34. The applicant retains the program description on record at RNP.

The staff has inspected the program on site at RNP for acceptability and compared the program's 10 attributes to the 10 attributes described in GALL XI.M34. Inspections of LRA scoping analyses, AMRs, and AMPs are a normal part of the agency's process for reviewing LRAs. Furthermore, the staff has reviewed the enhancements to determine whether the program remains adequate to manage the aging effects for which it is credited, and reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program. In letters dated April 28, and June 13, 2003, the applicant responded to the staff's RAI. The staff's RAI and the applicant's responses are discussed as follows.

The applicant stated that it will combine the Buried Piping and Tanks Inspection Program in LRA B.3.12 and the Buried Piping and Tanks Surveillance Program in LRA B.3.8 to manage aging effects associated with the buried piping and tanks. In RAI B.3.12-1, the staff asked the applicant to provide a list of all buried pipes that are covered under the inspection program and discuss why LRA B.3.8 does not cover buried cast iron piping and fittings because LRA B.3.12 covers buried cast iron piping and fittings.

In its response to RAI B.3.12-1, the applicant stated that the Buried Piping and Tanks Inspection Program manages aging by relying on the integrity of the coatings to prevent corrosion, and involves buried components within the scope of LR. The Buried Piping and Tanks Surveillance Program in LRA B.3.8 manages aging by using an impressed current cathodic protection system. The fuel oil system is the only piping system at RNP that has such a system. The buried fuel oil piping is not cast iron. The aspects relating to coating inspections in LRA B.3.8 rely on the activities described under the program in LRA B.3.12.

The applicant stated that LRA B.3.12 covers portions of the SWS, fire protection system, DSD system, and fuel oil system that are buried underground. The buried portions of the SWS and fire protection system piping that are covered under LRA B.3.12 are highlighted in the evaluation boundary drawings. The DSD system has two small segments of its jacket water system that are covered under LRA B.3.12. The fuel oil piping covered under LRA B.3.12 is discussed in the staff's safety evaluation of LRA B.3.8.

The staff finds the applicant's response to RAI 3.12-1 acceptable because the components that are covered in the inspection program are within the appropriate commodity group specified in GALL 2.3. The applicant also clarified the difference between the buried piping and tanks surveillance program and inspection program.

In LRA B.3.12, the applicant stated that leaks have occurred in the north service water header pipe in July 1995, March 1998, and September 1998. The applicant also stated that other buried pipes on site have not exhibited exterior corrosion such as experienced on the north service water header. In RAI B.3.12-2, the staff asked the applicant to (a) discuss how the exterior condition of other buried pipes could be assured unless the applicant performed an inspection via excavation of each buried pipe, (b) discuss how leaks in north service water header were detected, and (c) discuss how leaks can be detected in the buried fuel oil system piping without excavation.

In its response to RAIs B.3.12-2a and B.3.12-2b, the applicant stated that the corrosion on the north service water header resulted from holes which were caused by installation. The leakage from the header was detected by standing surface water appearing above the pipe. There have been no similar site experiences with other buried piping in the service water or fire protection systems.

The applicant stated that excavation and inspection of buried pipe is not required by the GALL program. It requires inspection when buried pipe is excavated for any reason. As stated in LRA B.3.12, RNP is consistent with the approved GALL program. If during inspections, there is an indication that coating is degraded, then the appropriate corrective actions will be determined under the Corrective Action Program, which will address aspects such as the degraded condition and additional inspection requirements.

The exterior inspection of the SWS piping involved only the affected portion of the north service water header. When the radwaste building was erected, the north service water header had to be rerouted. Three leaks have occurred in the north service water header in the section of pipe that was installed in 1984. The root cause of the March and September 1998 leaks is improper installation of the tapecoat external wrapping. The root cause of the July 1995 leak was caused by the misoperation of a backhoe during initial installation. Subsequently, this portion of the service water piping was raised above ground level.

In its response to RAI B.3.12-2c, the applicant stated that comparisons of fuel oil system flow totalizers located at each end of the buried piping from Unit 1 to the fuel oil storage location at Unit 2 can be used to monitor for a loss of fuel oil. Additionally, pressure testing of buried pipe assists in identifying underground leaks in the fuel oil system. The applicant monitors for underground fuel oil leakage to assure compliance with environmental permits and regulations. Minor leakage is expected to have essentially no impact on the system intended function. Regarding excavation of buried piping for the sole purpose of inspection, the applicant recognizes the potential for damaging or stressing coatings on buried piping and the impact it has on changing the electrochemical nature of the soil. The statements regarding leakage in LRA B.3.12 only refer to the scope of water systems included in the inspection program and make no inferences regarding fuel oil piping. Leak detection in fuel oil piping is discussed in the applicant's response to RAI B.3.8-2b which discusses the pressure testing used to monitor for leakage in the buried fuel oil piping.

The staff finds the applicant's response to RAI B.3.12-2 acceptable because the applicant has clarified their intentions to inspect buried pipe when it is excavated for any reason and perform pressure testing of the fuel oil system, which will satisfy GALL XI.M34.

In LRA B.3.12, the applicant stated that periodic excavations of buried piping for inspection are not warranted. In RAI B.3.12-3 and RAI B.3.12-4, the staff asked the applicant (a) if periodic excavations of buried piping are not warranted, to discuss the frequency of excavating inspection for each of the buried pipes covered under this program; and (b) to discuss the inspection history and results of all buried pipes covered under this program. If a buried pipe covered under this program has never been inspected since the commercial operation of the plant, the applicant should demonstrate that each buried pipe is within its design specifications and that its structural integrity is acceptable prior to and during the extended period of operation.

In its response to RAI B.3.12-3a and RAI B.3.12-4, the applicant stated that the inspection frequency for buried piping will depend primarily on maintenance and modification activities. There are no schedule frequencies for excavations. If, during maintenance, degraded pipe coatings are identified, then an appropriate sample would be determined based on engineering judgment and other relevant OE. LRA Section B.3.12 provides summary-level OE regarding leakage in buried pipe due to corrosion from the external environment.

In its response to RAI B.3.12-3b, the applicant stated that in GALL XI.M34, it is stated that, "Buried piping and tanks are inspected when they are excavated during maintenance. The inspections are performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems. However, because the inspection frequency is plant-specific and also depends on the plant OE, the applicant's proposed inspection frequency is to be further evaluated for the extended period of operation." As noted in LRA B.3.12, the site OE and the high soil resistance are the basis for not performing scheduled inspections.

Additionally, the SWS can tolerate some leakage and still achieve its safety function. A jockey pump normally maintains the site fire protection system headers at normal operating pressure. The inability of the jockey pump to maintain header pressure would provide notice of potential leakage in buried fire protection piping. Monthly checks of the DSD jacket water system expansion tank would reveal loss of jacket water system integrity and provide a means to detect leakage in DSD buried piping.

The applicant stated further that in NRC Inspection Report 50-261/91-21, the NRC staff concluded the following:

> Actions taken and closure was based on inspection results of the EDG fuel oil underground piping on March 27 and May 20, 1992. The piping examination demonstrated the piping coating was intact with no detectable piping degradation. The licensee (CP&L) concluded from this sample that the underground fuel oil piping had not degraded by galvanic corrosion. Additionally, the licensee completed a hardware upgrade of the cathodic protection system and was establishing base line operating parameters. The NRC found that the technical staff demonstrated a good knowledge level of the system operation and design. The inspector concluded the licensee had accomplished appropriate actions to verify the integrity of the underground fuel oil piping and had upgraded the cathodic protection system to an operable status.

The staff finds the applicant's response to RAI B.3.12-3 and RAI B.3.12-4 acceptable because the applicant has provided sufficient technical basis to support its opportunistic inspection of buried piping. The applicant's opportunistic inspection is consistent with GALL XI.M34.

In LRA B.3.12, the applicant stated that if coating fails, there will be ample time to identify and repair leaks before catastrophic failure. In RAI B.3.12-5, the staff asked the applicant to (a) discuss how much time is allowed for the operator to identify the pipe leak and take corrective actions before the leak in any of the buried pipe would challenge the intended function of the system, (b) discuss the potential for the operator to safely shutdown the plant given a leak has occurred in a buried pipe, and (c) discuss the consequence and safety significance of a catastrophic failure in each of the buried piping systems.

In its response to RAI B.3.12-5a, the applicant responded that there will be ample time to identify and repair leaks before catastrophic failure because of its OE with leakage in the SWS. The failures experienced to date were due to localized failures of the external coating of buried pipes. The bare spot or pipe material exposed by the defect in the coating becomes the anode, and the large intact coating area becomes the cathode. The local spot is preferentially attacked, resulting in a throughwall defect. Due to the concentrating effects of galvanic corrosion, the damage is very localized, and the adjacent piping with intact coatings is usually not damaged at all, which is the reason that the overall pipe retains its structural integrity. The leakage becomes detectable long before the localized openings can expand to the extent to weaken the pipe structurally.

The applicant stated that catastrophic failure of piping has been associated with cracking. Loss of material, not cracking, is the aging affect associated with this program. Catastrophic failure due to loss of material would require corrosion over large portions of the piping causing a loss of overall structural integrity. The GALL program prescribes the use of inspection when maintenance is performed as a means of detecting degradation of pipe coating, which could lead to unacceptable amounts of loss of material. The acceptance of this approach is dependent on site history. The RNP's site history shows that the soil has high resistivity and is not especially harsh. This has led to very few buried pipe failures. As noted above, localized damage would most likely be identified by indications of leakage or a loss of pressure in the system. On this basis, the inspection program is well suited to prevent catastrophic overall structural integrity.

In its response to RAI B.3.12-5b, the applicant stated that the aging management for the buried piping will have a high likelihood of preventing such catastrophic failure. Additionally, it should be noted that exterior coating is "non-Q" even though the pipe itself is Q." This is standard industry practice that reflects the fact that the pipe does not lose its safety function if the exterior coating fails. Based on the above, expected leakage resulting from coating failures will be small and will not affect the ability of operations personnel to safely shut down the plant.

In its response to RAI B.3.12-5c, the applicant stated that plant abnormal and emergency operating procedures provide instructions for mitigating a catastrophic failure of the SWS. However, such failures are considered extremely unlikely given the plant operating history and the proposed AMP.

The staff finds the applicant's response to RAI B.3.12-5 acceptable because the applicant has shown that the likelihood of catastrophic failure in the buried piping is low and that the operator has sufficient time and training to shut down the plant safely. This is consistent with GALL XI.M34.

In LRA B.3.12, the applicant stated that the inspection program will be enhanced by adding certain requirements. In RAI B.3.12-6, the staff asked the applicant to discuss the documentation process of these enhancements to assure that the commitments will be properly implemented during the extended period of operation and that the documentation will be available for future NRC inspection. In its response to RAI B.3.12-6, the applicant stated that its commitment is documented in LRA UFSAR Supplement, Subsection A.3.1.20. The staff finds the applicant's response to RAI B.3.12-6 acceptable because the staff has reviewed the UFSAR as discussed below and finds the commitment and associated documentation acceptable.

In LRA B.3.12, the applicant states that the objective of the inspection program is to prevent, monitor, and mitigate exterior corrosion of the buried piping and tanks. However, the program does not address the integrity of the inside surface of the buried pipes. The staff understands that LRA B.3.10, "Fuel Oil Chemistry Program," manages the aging effects on the inside surface of the buried fuel oil pipes; however, the Fuel Oil Chemistry Program does not specify the inspection of the inside surface of the buried fuel oil pipes. In RAI B.3.12-7, the staff asked the applicant to (a) discuss whether the Buried Piping and Tanks Inspection Program covers the inspection of the inside surface of the buried pipes, (if not, to discuss whether there is an inspection program to ensure the integrity of the inside surface of the buried pipes); and (b) discuss the potential of corrosion occurring on the inside surface of the buried pipes.

In its response to RAI B.3.12-7, the applicant stated that LRA B.3.12 does not cover inspection of the inside surfaces of buried pipe, and no such inspection program is proposed for aging management of buried fuel oil piping. The applicant stated that, however, the Fuel Oil Chemistry Program manages the aging mechanisms associated with the inside surfaces of fuel oil piping and components. With respect to internal surfaces, buried piping is subjected to conditions that are substantially similar to aboveground piping. The Fuel Oil Chemistry Program ensures the quality of the fuel oil by periodic sampling of fuel oil and by removing water from the bottom of the storage tank if any is found, and checks for aggressive bacteria. The program also credits periodic cleaning and inspections of large storage tanks. Prior to entering the buried pipe, fuel oil is drawn from the storage tanks well above the tank bottom. The fuel oil velocities in the tank are insufficient to entrain water into the supply piping, therefore, water would not be present in the piping system components. During search of site OE, the applicant did not identify any leakage or deleterious condition due to aging mechanisms associated with internal surfaces of carbon steel fuel oil pipes, fittings, and valves.

The staff finds the applicant's response to RAI B.3.12-7 acceptable because the applicant has shown that the inside surface of the buried fuel oil piping is adequately monitored for degradation by the Fuel Oil Chemistry Program in LRA B.3.10. The staff has found the Fuel Oil Chemistry Program acceptable as discussed in Section 3.3.2.3.6 of this SER.

3.3.2.3.7.3 UFSAR Supplement

In Section A.3.1.20 of the LRA, the applicant provides a UFSAR Supplement summary for the Buried Piping and Tanks Inspection Program which manages the aging effect of loss of material for buried components in RNP systems. There are no buried tanks in this program. The program includes preventive measures to mitigate corrosion by protecting the external surface of buried piping and components by use of, for example, coating or wrapping. The program includes visual examinations of buried components when they are made accessible by excavation for maintenance or for some other reason. Prior to the period of extended operation, the program will be enhanced to (1) incorporate a requirement to ensure an appropriate as-found pipe coating and material condition inspection is performed whenever buried piping within the scope of this program is exposed, (2) add precautions to ensure backfill with material that is free of gravel or other sharp or hard material that can damage the coating, (3) add a requirement that coating inspection shall be performed by qualified personnel to assess its condition, and (4) add a requirement that a coating engineer should assist in evaluation of any coating degradation noted during the inspection.

The staff finds that the summary in UFSAR Supplement A.3.1.20 is consistent with LRA Section B.3.12 and is, therefore, acceptable.

3.3.2.3.7.4 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.3.2.4 Aging Management of Plant-Specific Components

The following sections provide the results of the staff's evaluation of the adequacy of aging management for components in each of the auxiliary systems.

3.3.2.4.1 Sampling Systems

3.3.2.4.1.1 Summary of Technical Information in the Application

The description of the sampling system can be found in Section 2.3.3.1 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-7. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Components of the sampling systems are described in Section 2.3.3.1 of the submittal as within the scope of LR, and subject to an AMR. Table 2.3-7, on page 2.3-31 of the LRA, lists individual components of the system including closure bolting, valves, piping, tubing, and fittings. Closure bolting and external surfaces of carbon steel components are identified as subject to loss of material due to boric acid corrosion from exposure to borated water leaking from an adjacent system or component containing borated treated water. Carbon steel, SS, and nickel-based alloy exposed to the reactor coolant water or oxygenated water are subject to fatigue, cracking, and growth due to SCC and IGSCC, and loss of material due to crevice or pitting corrosion. Aluminum exposed to ambient air and gas and borated water leakage is identified as subject to loss of material due to aggressive chemical attack, crevice corrosion, and pitting corrosion. Carbon steel components are identified as subject to loss of material due to general, pitting, and crevice corrosion. Exposure of SS components to ambient air has no aging effects.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the sampling systems:

- Water Chemistry Program (B.2.2)
- Boric Acid Corrosion Program (B.3.2)
- One-Time Inspection Program (B.4.4)

The valves, piping, and fittings in the primary sampling system are also covered by TLAAs to address fatigue.

A description of these AMPs is provided in Appendix B of the LRA, and the TLAAs are discussed in Section 4.3.1 of the LRA.

3.3.2.4.1.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-7, 3.3-1, and 3.3-2 for the sampling systems. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff issued RAI 3.3-2 pertaining to the aging effects and AMP of the closure bolting in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.2 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff issued RAI 3.3-3 related to the assumptions made in the discussion column of aging effects for carbon steel externally exposed to indoor not-air-conditioned, containment air, and air-gas environments. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this SER, and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the sampling systems' SSCs to the environments described in Tables 2.3-7, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the sampling systems.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the sampling systems:

- Water Chemistry Program (3.0.3.3)
- Boric Acid Corrosion Program (3.0.3.4)
- One-Time Inspection Program (3.0.3.9)

These AMPs are credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for the sampling systems. The staff's evaluation of these AMPs is documented in Sections 3.0.3.3, 3.0.3.4, and 3.0.3.9 of this SER, respectively.

The fatigue of the primary sampling system components is addressed by the TLAAs in Section 4.3.1 of the LRA, "Reactor Coolant and Associated System Fatigue." This TLAA is evaluated in Section 4.3 of this SER.

After evaluating the applicant's AMR for each of the components in the sampling systems, the staff evaluated the AMPs and the TLAA listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table

3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs and TLAA to manage the aging effects for the materials and environments associated with the sampling systems.

3.3.2.4.2 Service Water System

3.3.2.4.2.1 Summary of Technical Information in the Application

The description of the SWS can be found in Section 2.3.3.2 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-8. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Components of the SWS are described in Section 2.3.3.2 of the submittal as being within the scope of LR, and subject to an AMR. Table 2.3-8, on page 2.3-33 of the LRA, lists individual components of the system including closure bolting, flow orifices/elements, service water booster pumps, service water pumps, service water supply header strainers, valves, piping, tubing, and fittings. Closure bolting and external surfaces of carbon steel and low-alloy steel components are identified as subject to loss of material due to boric acid corrosion from exposure to borated water leaking from an adjacent system or component containing borated treated water. Aluminum exposed to ambient air and gas and borated water leakage is identified as subject to loss of material due to aggressive chemical attack, and crevice and pitting corrosion.

The LRA identifies that carbon steel, galvanized steel, cast iron, and copper in air are subject to loss of material due to general external corrosion, and carbon steel and low-alloy steel in dripping boric acid are subject to loss of material due to boric acid corrosion. The LRA also identifies that SS, carbon steel, cast steel, cast iron, aluminum, copper alloy, and aluminum bronze in raw water and treated water are subject to loss of material due to general, pitting, and/or crevice corrosion, galvanic corrosion, MIC, biofouling, buildup of deposits, and/or selective leaching. Carbon steel and copper alloy components exposed to raw water are identified as being subject to loss of material due to erosion. Buried carbon steel is subject to loss of material due to general corrosion, crevice corrosion, pitting corrosion, galvanic corrosion, and MIC. Exposure of SS components to ambient air has no aging effects.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the SWS:

- Boric Acid Corrosion Program (B.3.2)
- Open-Cycle Cooling Water System Program (B.3.5)
- One-Time Inspection Program (B.4.4)
- Selective Leaching of Materials Program (B.4.5)
- Systems Monitoring Program (B.3.17)

- Preventive Maintenance Program (B.3.18)
- Aboveground Carbon Steel Tank Inspection Program (B.3.9)
- Buried Piping and Tanks Inspection Program (B.3.12)

A description of these AMPs is provided in Appendix B of the LRA.

3.3.2.4.2.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-8, 3.3-1 and 3.3-2 for the SWS. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff issued RAI 3.3-2 pertaining to the aging effects and AMP of the closure bolting in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.2 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-5, the applicant to clarify whether any of the auxiliary systems components for which the Preventive Maintenance Program is credited may rely on the monitoring of leakage. In addition, the applicant was requested to provide a discussion of the operating history of these components to demonstrate that the applicable aging effects will be adequately managed prior to the loss of their intended functions. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.5 of this SER, and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the SWS SSCs to the environments described in Tables 2.3-8, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the SWS.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the SWS:

- Boric Acid Corrosion Program (3.0.3.4)
- Open-Cycle Cooling Water System Program (3.0.3.7)
- One-Time Inspection Program (3.0.3.9)
- Selective Leaching of Materials Program (3.0.3.10)
- Systems Monitoring Program(3.0.3.11)
- Preventive Maintenance Program (3.0.3.12)
- Aboveground Carbon Steel Tank Inspection Program (3.3.2.3.5)
- Buried Piping and Tanks Inspection Program (3.3.2.3.7)

With the exception of the Aboveground Carbon Steel Tank Inspection Program and the Buried Piping and Tank Inspection Program, these AMPs are credited for managing the aging effects of components in several structures and systems and, therefore, are considered common

AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. These common AMPs are evaluated in Sections 3.0.3.4, 3.0.3.7, 3.0.3.9, 3.0.3.10, 3.0.3.11, and 3.0.3.12 of this SER. The Aboveground Carbon Steel Tank Inspection Program and the Buried Piping and Tank Inspection Program have been evaluated and found to be appropriate for this system. The Aboveground Carbon Steel Tank Inspection Program and the Buried Piping and Tank Inspection Program are discussed in Sections 3.3.2.3.5 and 3.3.2.3.7 of this SER, respectively.

The staff issued several RAIs related to the Aboveground Carbon Steel Tank Inspection Program (RAIs B.3.9-1 thru B.3.9-5) and the Buried Piping and Tank Inspection Program (RAIs B.3.12-1 thru B.3.12-7). All RAIs have been satisfactorily resolved. The details of the staff's evaluation of these RAIs are discussed in Sections 3.3.2.3.5 and 3.3.2.3.7 of this SER, respectively.

After evaluating the applicant's AMR for each of the components in the SWS, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the SWS.

3.3.2.4.3 Component Cooling Water System

3.3.2.4.3.1 Summary of Technical Information in the Application

The description of the CCW system can be found in Section 2.3.3.3 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-9. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Components of the CCW system are described in Section 2.3.3.3 of the submittal as within the scope of LR, and subject to an AMR. Table 2.3-9, on pages 2.3-34 and 2.3-35 of the LRA lists individual components of the system including CCW heat exchanger (HX) shell, tube sheet, and tubing, closure bolting, component cooling pumps, CCW surge tank, flow orifices/elements, hot leg sample HX shell and tubing, nonregenerative HX shell and tubing, pressurizer liquid sample HX shell and tubing, pressurizer (PZR) steam sample HX shell and tubing, rod drive cooling system cooler tubing, sample vessel HX shell and tubing, spent fuel pool cooling HX shell and tubing, SG blowdown HX shell and tubing, waste gas compressor cooler tubing and shell, valves, piping, tubing, and fittings. Closure bolting and external surfaces of carbon steel and low-alloy steel components are identified as being subject to loss of material due to boric acid corrosion from exposure to borated water leaking from adjacent systems or components containing borated treated water.

The LRA identifies that carbon steel and copper in air are subject to loss of material due to general external corrosion, and carbon steel and low-alloy steel in dripping boric acid are subject to loss of material due to boric acid corrosion. The LRA also identifies that SS, carbon steel, and copper alloy in raw water and treated water are subject to loss of material due to general, pitting, and/or crevice corrosion, galvanic corrosion, MIC, biofouling, buildup of deposits, and/or selective leaching. Carbon steel and copper alloy components exposed to raw water are identified as being subject to loss of material due to erosion. The LRA identifies that copper alloy components exposed to treated water (including steam) or air are subject to loss of heat transfer due to fouling of surfaces. Exposure of SS components to ambient air has no aging effects.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the CCW system:

- Boric Acid Corrosion Program (B.3.2)
- Open-Cycle Cooling Water System Program (B.3.5)
- Closed-Cycle Cooling Water System Program (B.2.5)
- One-Time Inspection Program (B.4.4)
- Preventive Maintenance Program (B.3.18)

A description of these AMPs is provided in Appendix B of the LRA.

3.3.2.4.3.2. Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-9, 3.3-1, and 3.3-2 for the CCW system. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff issued RAI 3.3-2 pertaining to the aging effects and AMP of the closure bolting in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.2 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-5, the applicant to clarify whether any of the auxiliary systems components for which the Preventive Maintenance Program is credited may rely on the monitoring of leakage. In addition, the applicant was requested to provide a discussion of the operating history of these components to demonstrate that the applicable aging effects will be adequately managed prior to the loss of their intended functions. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.5 of this SER, and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the CCW system SSCs to the environments described in Tables 2.3-9, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the CCW system.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the CCW system:

- Boric Acid Corrosion Program (3.0.3.4)
- Open-Cycle Cooling Water System Program (3.0.3.7)
- Closed-Cycle Cooling Water System Program (3.0.3.8)
- One-Time Inspection Program (3.0.3.9)
- Preventive Maintenance Program (3.0.3.12)

These AMPs are credited for managing the aging effects of components in several structures and systems and, therefore, are considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. These common AMPs are evaluated in Sections 3.0.3.4, 3.0.3.7, 3.0.3.8, 3.0.3.9, and 3.0.3.12 of this SER.

After evaluating the applicant's AMR for each of the components in the CCW system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the CCW system.

3.3.2.4.4 Chemical and Volume Control System

3.3.2.4.4.1 Summary of Technical Information in the Application

The description of the CVCS can be found in Section 2.3.3.4 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-10. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Components of the CVCS are described in Section 2.3.3.4 of the submittal as being within the scope of LR, and subject to an AMR. Table 2.3-10, on pages 2.3-37 and 2.3-38 of the LRA, lists individual components of the system including charging pump HX shell, regenerative HX shell and cover, charging pump HX tubing, charging pump HX water box, charging pump lube tanks, charging pump suction stabilizers and pulsation dampeners, charging pump(s), closure bolting, excess letdown HX shell and cover, excess letdown HX tubing, flow orifices/elements, regenerative HX tubing, shell and cover, seal injection filter, seal return filter, seal water HX shell and cover, seal water HX tubing, volume control tank, and valves, piping, tubing, and fittings.

Closure bolting and external surfaces of carbon steel components in RCS and in indoor plant air are identified as being subject to loss of material due to boric acid corrosion from exposure to borated water leaking from adjacent systems, or loss of material due to general corrosion, cracking initiation, and growth due to cyclic loading and SCC. The LRA identifies that carbon steel in air is subject to loss of material due to general external corrosion and boric acid corrosion. The LRA also identifies that several carbon steel and SS components in RC water or treated water (including steam) are also subject to fatigue and cracking initiation and growth due to SCC. Carbon steel, SS, copper alloy, and nickel-based alloys in treated water (including steam) are subject to loss of material due to general, pitting and crevice corrosion, and galvanic corrosion due to dissimilar metals. The LRA identifies that carbon steel, SS, and copper alloys in treated water (including steam) are subject to loss of heat transfer due to fouling of heat transfer surfaces. The LRA also identifies the CASS in RC water as subject to loss of fracture toughness due to thermal aging embrittlement. The LRA does not identify any aging effects for SS, or copper alloys in air, or for carbon steel, copper alloys, or SS in lubricating oil.

Aging Management Program

The following AMPs are utilized to manage aging effects in the CVCS:

- ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1)
- Water Chemistry Program (B.2.2)
- Boric Acid Corrosion Program (B.3.2)
- Bolting Integrity Program (B.3.4)
- Closed-Cycle Cooling Water System Program (B.2.5)
- One-Time Inspection Program(B.4.4)
- Systems Monitoring Program (B.3.17)
- Preventive Maintenance Program (B.3.18)

The charging pumps, lube tanks, excess letdown HX shell and cover/ tubing, flow orifices/elements, regenerative HX tubing, shell, and cover, seal injection filter, seal return filter, valves, piping, tubing and fittings are also covered by TLAAs to address fatigue.

A description of these AMPs is provided in Appendix B of the LRA and the TLAAs are discussed in Section 4.3.1 of the LRA.

3.3.2.4.4.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-10, 3.3-1, and 3.3-2 for the CVCS. During its review, the staff determined that additional information was needed to complete its review.

In row 14 of LRA Table 3.3-1, the applicant identified the loss of material from crevice, general, and pitting corrosion as an aging effect/mechanism for carbon steel and SS components in a treated water environment in the CVCS. The applicant further indicated that the applicable AMP is the RNP's Closed-Cycle Cooling Water System Program (AMP B.2.5). The staff reviewed AMP B.2.5 and found that CVCS is not within the scope of AMP B.2.5. Similarly, row 8 of Table 3.3-1 for HXs in CVCS is not within the scope of AMP B.2.5. By letter dated February 11, 2003, the staff requested, in RAI 3.3.4-6, the applicant to explain these discrepancies.

In its response dated April 28, 2003, the applicant clarified that, in addition to the systems listed in AMP B.2.5, AMP B.2.5 is credited for managing aging effects for components interfacing with the CCW system. This includes components in the RHR system, SI system, and CVCS, which are cooled by the CCW system.

On the basis of its review, the staff finds the applicant's response acceptable because the aging effects for components in question are now within the scope of AMP B.2.5 by the applicant's clarification. The staff considers the issues related to RAI 3.3.4-6 to be resolved.

In LRA Table 2.3-10 for CVCS, the applicant did not identify row 4 of the LRA Table 3.3-1 as an item in AMR results for charging pumps in CVCS. The applicant described its bases for excluding the aging effect of cracking in the discussion column of Table 3.3-1, row 4. By letter dated February 11, 2003, the staff requested, in RAI 3.3.4-7, the applicant to provide OE to support the stated bases for excluding the cracking due to SCC for the RNP CVCS charging pump.

In its response dated April 28, 2003, the applicant stated that RNP reviewed industry and plant-specific OE to support and validate the AMR methodology and the resulting aging effects/mechanisms. The general methodology is described in LRA Section 3.3.1.2 for auxiliary systems. The applicant stated that, although GALL does identify cracking" as an applicable aging effect for the high-pressure pump casing, the RNP LR review of industry OE has identified only one case of cracking in a charging pump casing. This case was identified in NRC IN 80-38, "Cracking in Charging Pump Casing Cladding." This cracking was specific to a different type of charging pump manufactured by the Pacific Pumps Division of Dresser Industries. These pumps were carbon steel with SS cladding welded to the inner surface, and the cracking was in the weld and was attributed to high-cycle vibration. The RNP CVCS uses union reciprocating type pumps with SS casings. Therefore, this aging effect was deemed not applicable as a result of the OE review.

The applicant also stated that, at RNP, cracking was identified in the C" charging pump bore hole. This was caused by high hoop-stresses in the cylinder wall due to improperly fitted cylinder inserts. The maintenance practices were changed to use more exacting tolerances. This failure was therefore not considered an aging concern for properly maintained charging pumps. The applicant indicated that no other instances of cracking were identified in the OE review.

The applicant further stated that as stated in LRA Table 3.3-1, row 4, a temperature criterion of greater than 140 °F is used as the threshold for susceptibility of austenitic SSs to SCC. This is based upon industry experience and industry guidance. The RNP AMR includes a review of industry and site OE. No instances were identified that would bring this temperature threshold into question.

On the basis of its review, the staff finds the applicant's response reasonable and acceptable because the applicant's bases for excluding the aging effects of cracking in the RNP CVCS charging pump are consistent with the industry and site OE. The staff considers the issues related to RAI 3.3.4-7 to be resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the CVCS SSCs with the environments described in Tables 2.3-10, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the CVCS.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the CVCS:

- ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD (3.0.3.2)
- Water Chemistry Program (3.0.3.3)
- Boric Acid Corrosion Program (3.0.3.4)
- Bolting Integrity Program (3.0.3.6)
- Closed-Cycle Cooling Water System Program (3.0.3.8)
- One-Time Inspection Program (3.0.3.9)
- Systems Monitoring Program (3.0.3.11)
- Preventive Maintenance Program (3.0.3.12)

These AMPs are credited for managing the aging effects of components in several structures and systems and, therefore, are considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. These common AMPs are evaluated in Sections 3.0.3.2, 3.0.3.3, 3.0.3.4, 3.0.3.6, 3.0.3.8, 3.0.3.9, 3.0.3.11, and 3.0.3.12 of this SER.

The fatigue of the CVCS components is addressed by the TLAAs in Section 4.3.1 of the LRA, "Reactor Coolant and Associated System Fatigue." This TLAA is evaluated in Section 4.3 of this SER.

After evaluating the applicant's AMR for each of the components in the CVCS system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs and TLAAs to manage the aging effects for the materials and environments associated with the CVCS.

3.3.2.4.5 Instrument Air System

3.3.2.4.5.1 Summary of Technical Information in the Application

The description of the instrument air (IA) system can be found in Section 2.3.3.5 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-11. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Components of the IA system are described in Section 2.3.3.5 of the submittal as within the scope of LR, and subject to an AMR. Table 2.3-11, on page 2.3-39 of the LRA, lists individual components of the system including closure bolting, IA filters, IA regulator body/bonnet, valves, piping, tubing, and fittings. Closure bolting and external surfaces of carbon steel components are identified as subject to loss of material due to boric acid corrosion from exposure to borated water leaking from an adjacent system or component containing borated treated water. Elastomers and miscellaneous piping components are identified as subject to change in material properties, hardening, cracking, and loss of strength due to elastomer degradation and loss of material due to various degradation mechanisms from exposure to ambient air and gas, treated water (including steam), and borated water leakage. Aluminum exposed to ambient air and gas and borated water leakage is identified as subject to loss of material due to aggressive chemical attack, crevice and pitting corrosion. Exposure of SS, aluminum, and copper alloy components to ambient air has no aging effects.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the IA system:

- Boric Acid Corrosion Program (B.3.2)
- Preventive Maintenance Program (B.3.18)

A description of these AMPs is provided in Appendix B of the LRA.

3.3.2.4.5.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-11, 3.3-1, and 3.3-2 for the IA system. During its review, the staff determined that additional information was needed to complete its review.

In Table 3.3.1, row 18, the applicant stated that the components in the IA system at RNP contain clean, dried air. The applicant also stated that the aging mechanisms in the GALL Report are not applicable to the RNP IA system because moisture is controlled. It should be noted that in the IA system, components that are located upstream of the air dryers are generally exposed to wet air/gas environment and, therefore, may be subject to the aging effect of loss of material due to general and pitting corrosion. In addition, it is reasonable to assume that components downstream of the dryers are exposed to a dry air/gas environment. However, this may not be supported by the OE. For an example, NRC IN 87-28, "Air Systems Problems at U.S. Light Water Reactors," states that "A loss of decay heat removal and significant primary system heat up at Palisades in 1978 and 1981 were caused by water in the air system." This experience implies that the air/gas system downstream of the dryer may not be dry. By letter dated February 11, 2003, the staff requested, in RAI 3.3.5-8, the applicant to provide the technical basis for not identifying loss of material as an aging effect for these components, including a discussion of the plant specific OE related to components that are exposed to IA environment to support its conclusion.

In its response dated April 28, 2003, the applicant clarified that associated with the RNP IA compressors are Atlas Copco adsorption type desiccant dryers, both capable of producing dry air with a dew point less than 0 °F. The dryer operates with continuous regeneration, utilizing air that bypassed the compressor aftercooler. This air is still hot and unsaturated and is used to regenerate the drum by evaporating the moisture adsorbed through the drying process. The desiccant dryer is efficient in removing moisture and is capable of design dew points of less than 0 °F. The lower dew point for compressed air will prevent condensation and buildup of foreign material in air operated valves.

The applicant further stated that dry air is provided by the IA system by design of the compressors and air dryers. Dry air quality is maintained during operation by a program of preventive and post-maintenance testing and operator actions. Dry air quality is demonstrated by the trouble free operation of the downstream instruments and components, as indicated by plant OE discussed below.

Quarterly testing is performed to verify IA dew point using PM procedures, and is also performed after maintenance on the air dryers using post-maintenance testing procedures. The IA dew point is verified to be less than 0 °F by measurement at four locations in the IA system. Operations personnel verify each shift that the IA receivers contain dry air.

The applicant indicated that OE since the installation of the D" high capacity IA compressor was examined to identify potential negative trends with respect to IA quality. Work orders for the IA filters downstream of the air receivers, upstream of the main steam isolation valves MSIVs), and upstream of the main steam power-operated relief valves (PORVs) were reviewed to identify potential occurrences of problems that might be associated with poor air quality, such as moisture. No such occurrences were identified. Work orders for a representative sample of downstream components were reviewed, and no occurrences were identified of problems that might be associated with poor IA quality.

The applicant concluded that loss of material was not identified as an aging effect for IA components subject to AMR based on the dry air delivered by the IA system downstream of the air dryers. Dry air is provided by system design, and is maintained by system operation and testing requirements. Dry air is further demonstrated by a review of plant-specific OE related to components that are exposed to the IA environment.

On the basis of its review, the staff finds the applicant's response acceptable because the applicant's system design, PM, and testing procedures resulted in dry air quality that is demonstrated by trouble free operation of the downstream instruments and components, as indicated by plant OE. The staff considers the issues related to RAI 3.3.4-8 to be resolved.

By letter dated February 11, 2003, the staff issued RAI 3.3-2 pertaining to the aging effects and AMP of the closure bolting in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.2 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff issued RAI 3.3-3 related to the assumptions made in the discussion column of aging effects for carbon steel externally exposed to indoor not-air-conditioned, containment air, and air-gas environments. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this SER, and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the IA system SSCs with the environments described in Tables 2.3-11, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the IA system.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the IA system:

- Boric Acid Corrosion Program (3.0.3.4)
- Preventive Maintenance Program (3.0.3.12)

These AMPs are credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for the IA system. The staff's evaluation of these AMPs is documented in Sections 3.0.3.4 and 3.0.3.12 of this SER, respectively.

After evaluating the applicant's AMR for each of the components in the IA system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the IA system.

3.3.2.4.6 Nitrogen Supply/Blanketing System

3.3.2.4.6.1 Summary of Technical Information in the Application

The description of the nitrogen supply/blanketing system can be found in Section 2.3.3.6 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-12. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Table 2.3-12 of the LRA listed individual components in the nitrogen supply/blanketing system that are within the scope of LR and subject to AMR. The components include closure bolting, flow orifices/elements, PZR N_2 accumulator tank, steam dump accumulator tank, valves, piping, tubing, and fittings.

SS and copper alloy components in indoor not-air-conditioned, containment air, air and gas, borated water leakage, and outdoor environments are determined by the RNP AMR to have no aging effects requiring management for these environments. The applicant stated that the applicable RNP environments do not promote concentration of contaminants or include exposure to aggressive chemical species. The applicant also stated that boric acid is not an aggressive chemical species for SS and copper alloys.

Carbon steel components in air and leaking chemically treated borated water are identified as being subjected to loss of material due to boric acid corrosion. External surfaces of carbon steel components in indoor not-air-conditioned, containment air, and air and gas environments are assumed not to be susceptible to corrosion if they are located in areas protected from the weather, not subjected to condensation, and not subjected to aggressive chemical attack.

<u>Aging Management Programs</u>

The following AMP is utilized to manage aging effects in the nitrogen supply/blanketing system:

- Boric Acid Corrosion Program (B.3.2)

A description of this AMP is provided in Appendix B of the LRA.

3.3.2.4.6.2 Staff Evaluation

<u>Aging Effects</u>

The staff reviewed the information in Tables 2.3-12, 3.3-1, and 3.3-2 for the nitrogen supply/blanketing system. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff issued RAI 3.3-2 pertaining to the aging effects and AMP of the closure bolting in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.2 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff issued RAI 3.3-3 related to the assumptions made in the discussion column of aging effects for carbon steel externally exposed to indoor not-air-conditioned, containment air, and air-gas environments. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this SER, and is characterized as resolved.

In Item 23 of LRA Table 3.3-2, the applicant identified flow orifices" as one of the component commodities. However, Table 2.3-12 did not identify row 23 of Table 3.3-2 under flow orifices. By letter dated February 11, 2003, the staff requested, in RAI 3.3.6-9, the applicant to clarify this discrepancy.

In its response dated April 28, 2003, the applicant stated that LRA Table 3.3 -2, row 23, deals with components fabricated from SS. The nitrogen supply/blanketing system flow orifices/elements are carbon steel. Therefore, row 23 of LRA Table 3.3-2 was not identified as an applicable reference. On the basis of its review, the staff finds the applicant's response acceptable because it clarified that the flow orifices included in LRA Table 2.3-12 are made of different material and therefore, LRA Table 3.3-2, row 23 is not an applicable reference.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the nitrogen supply/blanketing system environments described in Tables 2.3-12, 3.3-1, and 3.3-2 of the LRA are consistent with industry experience to address the combination of the listed materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the nitrogen supply/blanketing system.

Aging Management Programs

The applicant credited the following AMP for managing the aging effects in the nitrogen supply/blanketing system:

- Boric Acid Corrosion Program (3.0.3.4)

The AMP is credited for managing the aging effects of several components in other structures and systems and is, therefore, considered a common AMP. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0.3.4 of this SER.

After evaluating the applicant's AMR for each of the components in the nitrogen supply/blanketing system, the staff evaluated the AMP listed above to determine if it is appropriate for managing the identified aging effects for this system. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMP to manage the aging effects for the materials and environments associated with the nitrogen supply/blanketing system.

3.3.2.4.7 Radioactive Equipment Drains

3.3.2.4.7.1 Summary of Technical Information in the Application

The description of radioactive equipment drains (REDS) can be found in Section 2.3.3.7 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-13. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1and 3.3-2.

Aging Effects

Table 2.3-13 of the LRA listed individual components in REDS that are within the scope of LR and subject to AMR. The only components listed are piping and fittings.

SS components in raw water environment are identified as being subjected to loss of material due to loss of material from crevice corrosion, general corrosion, and pitting.

Aging Management Programs

The applicant stated that the potential aging effects/mechanisms do not affect the ability of the components to perform their intended functions. Therefore, no AMP is required to manage aging effects in REDS.

3.3.2.4.7.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-13, 3.3-1, and 3.3-2 for REDS. In Table 3.3.2, row 8 of the LRA, the applicant identified loss of material due to crevice corrosion, general corrosion, and pitting as the potential aging effects/mechanisms for the SS components in REDS. This system was not addressed in the GALL Report. The REDS route floor drainage to the liquid waste processing system to drain raw water from rooms following actuation of fire suppression systems. By letter dated February 11, 2003, the staff, in RAI 2.3.3.7-2, requested the applicant to clarify which portions of this system are included within the scope of LR and subject to an AMR. In its response dated April 28, 2003, the applicant described the portions of the REDS that are within the scope of LR and identified aging effect of loss of material due to crevice corrosion, pitting corrosion, and MIC. It should be noted that the LRA identifies loss of material due to crevice corrosion, general corrosion, and pitting for these SS components.

During a subsequent telephone discussion on August 13, 2003, the applicant clarified that the aging mechanisms identified in its RAI response are correct and should be considered to supersede the aging mechanisms presented in the LRA. The staff finds this clarification acceptable because the SS components are not susceptible to general corrosion, while the raw water environment is assumed to have a potential source of MIC. However, the applicant has requested to provide the above information under oath and affirmation. This is Confirmatory Item 3.3.2.4.7-1.

Based on the applicant's response to the Confirmatory Item 3.3.2.4.7-1, in a letter dated August 14, 2003 (Serial RNP-RA/03-0094), the staff finds that the aging effects that result from contact of REDS environments described in Tables 2.3-13, 3.3-1, and 3.3-2 of the LRA are consistent with industry experience to address the combination of the listed materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in REDS. Confirmatory Item 3.3.2.4.7-1 is resolved.

Aging Management Programs

As discussed above, in its response to RAI 2.3.3.7-2, the applicant stated that the identified aging effects do not affect the intended function of the REDS, and therefore, do not require management for the period of extended operation. On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff determined that the applicant needs to provide additional information to support its conclusion that the identified aging effects do not affect the intended function of the REDS, and therefore, do not require management for the period of extended operation. On June 17, 2003, in a telephone conference, the staff discussed the issue further with the applicant. Subsequent to the telephone conference, by an electronic correspondence dated

June 19, 2003, the applicant provided the following information to support its conclusion on the aging management of REDS.

The applicant stated that this piping system is normally at nearly ambient pressure. The SS piping and components are normally dry. Inspections are performed under the RNP Equipment Leak Reduction Program that includes operator rounds, system walkdowns, and other routine inspections. The applicant also stated that blockage of system components is unlikely. Because the system is normally dry, the rate of corrosion product formation is expected to be very small. Flow blockage from external sources is also unlikely. Each floor drain has a slotted SS strainer. The area available for flow through the strainer is about 14 in^2, which is larger than the 8 in^2 cross-sectional area of the 3-inch diameter, floor drain piping. The floor drain is thus protected from blockage by large objects and sediment is trapped before it can enter the system. Furthermore, the applicant stated that the operator rounds include the RAB room and area checks to identify blocked drains, leakage, and any abnormal housekeeping conditions. Should an unacceptable condition be identified, corrective action consistent with the plant procedures is initiated. The applicant also stated that the decontamination activities include the decontamination of floor drains on an as needed" frequency.

Moreover, the applicant stated that although degradation of the REDS is not expected to occur, leakage from non-safety-related systems causing loss of safety-related system intended functions has been examined by the LR 10 CFR 54.4(a)(2) analysis. No spatial relationship between the REDS and safety-related SSCs was identified such that REDS failure could adversely impact on the performance of a safety-related SSCs intended function.

Based on its review of the above information, the staff finds that the applicant has provided adequate information to justify that no AMP is required to manage the aging effects of the REDS because the applicant has demonstrated that leaking and blockage of the REDS are unlikely, the potential flow blockage will be identified and corrected timely by the applicant's routine inspection and other activities, and leakage of the REDS would not adversely impact on the performance of the SSCs. However, the applicant is requested to provide the above information under oath and affirmation. By letter dated August 14, 2003, the applicant provided the requested information. Confirmatory Item 3.3.2.4.7-1 is resolved.

Based on the applicant's response to the Confirmatory Item 3.3.2.4.7-1, in a letter dated August 14, 2003 (Serial RNP-RA/03-0094), the staff concurs with the applicant's conclusion that no AMP is required to manage the aging effects of the REDS.

3.3.2.4.8 Primary and Demineralized Water System

3.3.2.4.8.1 Summary of Technical Information in the Application

The description of the primary and demineralized water system can be found in Section 2.3.3.8 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in the revised LRA Table 2.3-14. The components, aging effects, and aging management programs are provided the revised LRA Tables 3.3-1 and 3.3-2.

<u>Aging Effects</u>

The revised Table 2.3-14 of the LRA listed individual components in the primary and demineralized water system that are within the scope of license renewal and subject to AMR. The components include valves, piping and fittings, and deep well pumps.

SS components in treated water (including steam) environments are identified as subject to loss of material from crevice and pitting corrosion by demineralized water from the condensate storage tank (CST). SS and copper alloy components in indoor not-air-conditioned, containment air, air and gas, borated water leakage, and outdoor environments have no aging effects requiring management for these environments. The applicant stated that the applicable RNP environments do not promote concentration of contaminants or include exposure to aggressive chemical species. The applicant also stated that boric acid is not an aggressive chemical species for SS.

Carbon steel components in treated water (including steam) environments are identified as subject to loss of material from crevice, general, pitting, and galvanic corrosion by demineralized water from the CST. Carbon steel piping and valves in outdoor ambient conditions are identified as subject to loss of material from general, pitting, and crevice corrosion. Carbon steel, copper alloys, and SS in raw water are identified as subject to loss of material from general (for carbon steel only), crevice, and pitting corrosion, and MIC.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the primary and demineralized water system:

- Water Chemistry Program (B.2.2)
- One-Time Inspection Program (B.4.4)
- Systems Monitoring Program (B.3.17)
- Preventive Maintenance Program (B.3.18)
- AboveGround Carbon Steel Tank Inspection Program (B.3.9)

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the primary and demineralized water system will be adequately managed by these AMPs during the period of extended operation.

3.3.2.4.8.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-14, 3.3-1, and 3.3-2 for the primary and demineralized water system. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-5, the applicant to clarify whether any of the auxiliary systems components for which the Preventive Maintenance Program is credited may rely on the monitoring of leakage. In addition, the applicant was requested also to provide a discussion of the operating history of these components to demonstrate that the applicable aging effects will be adequately managed prior to the loss of their intended functions. This is Open Item 2.3.3.8-1. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.5 of this SER, and is characterized as resolved.

Table 2.3-14 of LRA refers to row 5 of Table 3.3-1 for AMR results. However, row 5 of Table 3.3-1 did not include primary and demineralized water system under the component/commodity group column. By letter dated February 11, 2003, the staff requested, in RAI 3.3.8-10, the applicant to clarify this apparent discrepancy. In its response dated April 28, 2003, the applicant stated that LRA Table 3.3-1, row 5, deals with several categories of components, including external surfaces of carbon steel components. The external surfaces of carbon steel components in the primary and demineralized water system have been included here. On the basis of its review, the staff finds the applicant's response acceptable because it clarifies that LRA Table 3.3-1, row 5 included the carbon steel components in the primary and demineralized water system.

In its letter dated September 16, 2003, RNP agreed to include in the scope of license renewal the three deep well pumps and associated piping to provide a backup source of water for the auxiliary feedwater system. As a result, Open Item 2.3.3.8-1 is resolved. The Open Item 2.3.3.8-1 and how it was resolved, is discussed in Section 2.3.3.8.2. The revised component/commodity groups and the associated revised aging management evaluations are given in the revised Tables 2.3-14, 3.3-1 and 3.3-2 provided in the applicant's September 16, 2003, letter. On the basis of its review of the applicant's revised aging management evaluations on the components in the expanded scope, the staff finds that the applicant's response acceptable because the applicant has adequately identified the materials, environments, aging effects, and AMPs for the expanded components.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the primary and demineralized water system environments described in the revised Tables 2.3-14, 3.3-1 and 3.3-2 of the LRA are consistent with industry experience to address the combination of the listed materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the primary and demineralized water system.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the primary and demineralized water system:

- Water Chemistry Program (3.0.3.3)
- One-Time Inspection Program (3.0.3.9)
- Systems Monitoring Program (3.0.3.11)
- Preventive Maintenance Program (3.0.3.12)
- Above Ground Carbon Steel Tank Inspection Program (3.3.2.3.5)

With the exception of the AboveGround Carbon Steel Tank Inspection Program, these AMPs are credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. These common AMPs are evaluated in Sections 3.0.3.3, 3.0.3.9, 3.0.3.11, and 3.0.3.12 of this SER. The AboveGround Carbon Steel Tank Inspection Program has been evaluated and founded to be acceptable for managing aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.3.2.3.5 of this SER.

After evaluating the applicant's AMR for each of the components in the primary and demineralized water system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL report. For the components identified in the revised LRA Table 3.3-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the primary and demineralized water system.

3.3.2.4.9 Spent Fuel Pool Cooling System

3.3.2.4.9.1 Summary of Technical Information in the Application

The description of the SFPCS can be found in Section 2.3.3.9 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-15. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Table 2.3-15 of the LRA listed individual components in the SFPCS that are within the scope of LR and subject to AMR. The components include closure bolting, flow orifices/elements, valves, piping, and fittings.

SS components in treated water (including steam) environments are identified as subject to loss of material from crevice and pitting corrosion. The applicant assumed that oxygen and contaminants are present such that crevice corrosion is possible if low flow conditions exist.

Carbon steel components in air and leaking chemically treated borated water environments are identified as subject to loss of material due to boric acid corrosion which can lead to loss of mechanical closure integrity.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the SFPCS:

- Water Chemistry Program (B.2.2)
- Boric Acid Corrosion Program (B.3.2)

A description of these AMPs is provided in Appendix B of the LRA.

3.3.2.4.9.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-15, 3.3-1, and 3.3-2 for the SFPCS. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff issued RAI 3.3-2 pertaining to the aging effects and AMP of the closure bolting in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.2 of this SER, and is characterized as resolved.

In response to the RAI 2.3.3.9-1, the applicant agreed to include the spent fuel pit makeup path from the refueling water storage tank (RWST) to the spent fuel pool (SFP) within the scope of license renewal. As a result, additional components (closure bolting, flow orifice/elements, SFP cooling demineralizer, SFP cooling filter, refueling water purification pump, valves, piping, and fittings) added to Tables 2.3-15, 3.3-1 and 3.3-2.

On the basis of its review of the information provided in the LRA and the additional information included in response to RAI 3.3-2 and RAI 2.3.3.9-1, the staff finds that the aging effects that result from contact with the SFPCS environments described in Tables 2.3-15, 3.3-1, and 3.3-2 of the LRA are consistent with industry experience to address the combination of the listed materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the SFPCS.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the SFPCS:

- Water Chemistry Program (3.0.3.3)
- Boric Acid Corrosion Program (3.0.3.4)

In row 1 of LRA Table 3.3-2, the applicant identified flow orifices/elements, valves, piping, and fittings as components subject to loss of material from crevice and pitting corrosion in treated water (including steam). The applicant assumed that oxygen and contaminants are present such that crevice corrosion is possible if low flow conditions exist. The applicant stated that the GALL Report, Sections VII.E.1 and VII.A.3, notes that effects of crevice and pitting corrosion on SS are not significant in chemically treated borated water. Therefore, the applicant concluded that the Water Chemistry Program alone is sufficient to manage the aging mechanisms. During a telephone conversation on June 9, 2003, the applicant clarified that the SFPCS is within the scope of the One-Time Inspection Program as described in LRA B.4.4. The applicant further stated that the One-Time Inspection Program is used to verify the effectiveness of the Water Chemistry Program.

The Water Chemistry Program, the Boric Acid Corrosion Program, and the One-Time Inspection Program are credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Sections 3.0.3.3, 3.0.3.4, and 3.0.3.9 of this SER, respectively.

After evaluating the applicant's AMR for each of the components in the SFPCS, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the SFPCS.

3.3.2.4.10 Containment Purge System

3.3.2.4.10.1 Summary of Technical Information in the Application

The description of the containment purge system can be found in Section 2.3.3.10 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-16. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Table 2.3-16 of the LRA listed individual components in the containment purge system that are within the scope of LR and subject to AMR. The components include closure bolting, ductwork and fittings, equipment frames and housings, flexible collars and valves.

Carbon steel components in air, and leaking chemically treated borated water, are identified as being subjected to loss of material due to boric acid corrosion. The RNP AMR assumed that external surfaces of carbon steel components in indoor not-air-conditioned, containment air, and air and gas environments would not be susceptible to corrosion if they are located in areas protected from the weather, not subjected to condensation, and not subjected to aggressive chemical attack.

The RNP AMP determined that galvanized steel components have no aging effects requiring management when exposed to indoor not-air-conditioned, containment air, and borated water leakage environments. These components would not experience age-related degradation requiring management in these environments, as determined in the RNP AMR methodology.

For components made of elastomer (neoprene) material in warm and moist air, hardening, cracking, and loss of strength due to elastomer degradation, and loss of material due to wear are identified as aging effects/mechanism.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the containment purge system:

- Boric Acid Corrosion Program (B.3.2)
- Systems Monitoring Program (B.3.17)

A description of these AMPs is provided in Appendix B of the LRA.

3.3.2.4.10.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-16, 3.3-1, and 3.3-2 for the containment purge system. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-1, the applicant to clarify the discrepancy between Table 3.3-1, row 2 and Section B.3.17, "Systems Monitoring Program," regarding the aging effect/mechanisms for elastomer components included in numerous ventilation systems. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.1 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff issued RAI 3.3-2 pertaining to the aging effects and AMP of the closure bolting in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.2 of this SER, and is characterized as resolved.
By letter dated February 11, 2003, the staff issued RAI 3.3-3 related to the assumptions made in the discussion column of aging effects for carbon steel externally exposed to indoor not-air-conditioned, containment air, and air-gas environments. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-4, the applicant to provide the basis for not considering boric acid corrosion as an applicable aging effect for galvanized steel components included in Table 3.3-1, row 20. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.4 of this SER, and is characterized as resolved.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the containment purge system:

- Boric Acid Corrosion Program (3.0.3.4)
- Systems Monitoring Program (3.0.3.12)

These AMPs are credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Sections 3.0.3.4 and 3.0.3.12 of this SER, respectively.

After evaluating the applicant's AMR for each of the components in the containment purge system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the containment purge system.

3.3.2.4.11 Rod Drive Cooling System

3.3.2.4.11.1 Summary of Technical Information in the Application

The description of the rod drive cooling system can be found in Section 2.3.3.11 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-17. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Table 2.3-17 of the LRA listed individual components in the rod drive cooling system that are within the scope of LR and subject to AMR. The components include closure bolting, ductwork and fittings, equipment frames and housings, and flexible collars.

Carbon steel components in air and leaking chemically treated borated water are identified as being subject to loss of material due to boric acid corrosion. External surfaces of carbon steel components in indoor not-air-conditioned, containment air, and air and gas environments are not susceptible to corrosion if they are located in areas protected from the weather, not subjected to condensation, and not subjected to aggressive chemical attack. Galvanized steel components in indoor not-air-conditioned, containment air, and borated water leakage environments have no aging effect.

For components made of elastomer (neoprene) material in warm and moist air are identified as being subject to loss of material due to hardening, cracking, and loss of strength due to elastomer degradation.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the rod drive cooling system:

- Boric Acid Corrosion Program (B.3.2)
- Systems Monitoring Program (B.3.17)

A description of these AMPs is provided in Appendix B of the LRA.

3.3.2.4.11.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-17, 3.3-1, and 3.3-2 for the rod drive cooling system. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-1, the applicant to clarify the discrepancy between Table 3.3-1, row 2 and Section B.3.17, "Systems Monitoring Program," regarding the aging effect/mechanisms for elastomer components included in numerous ventilation systems. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.1 of this SER, and is characterized as resolved.
By letter dated February 11, 2003, the staff issued RAI 3.3-2 pertaining to the aging effects and AMP of the closure bolting in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.2 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff issued RAI 3.3-3 related to the assumptions made in the discussion column of aging effects for carbon steel externally exposed to indoor not-air-conditioned, containment air, and air-gas environments. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-4, the applicant to provide the basis for not considering boric acid corrosion as an applicable aging effect for galvanized steel components included in Table 3.3-1, row 20. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.4 of this SER, and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the rod drive cooling system environments described in Tables 2.3-17, 3.3-1, and 3.3-2 of the LRA are consistent with industry experience to address the combination of the listed materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the rod drive cooling system.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the rod drive cooling system:

- Boric Acid Corrosion Program (3.0.3.4)
- Systems Monitoring Program (3.0.3.12)

These AMPs are credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Sections

3.0.3.4 and 3.0.3.12, respectively, of this SER.

After evaluating the applicant's AMR for each of the components in the rod drive cooling system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the rod drive cooling system.

3.3.2.4.12 Heating Ventilation, and Air Conditioning Auxiliary Building

3.3.2.4.12.1 Summary of Technical Information in the Application

The description of the HVAC auxiliary building can be found in Section 2.3.3.12 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-18. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Components of the HVAC auxiliary building are described in Section 2.3.3.12 of the submittal as being within the scope of LR, and subject to an AMR. Table 2.3-18, on page 2.3-46 of the LRA, lists individual components of the system including closure bolting, ductwork and fittings, equipment frames and housing, flexible collars, and heating/cooling coils. Closure bolting and external surfaces of carbon steel components are identified as subject to loss of material due to boric acid corrosion from exposure to borated water leaking from an adjacent system or component containing borated treated water. The LRA identifies that carbon steel and copper alloys in air, and exposure to borated water leakage, are subject to loss of material due to general external corrosion, crevice corrosion, pitting corrosion, and MIC.

The LRA also identifies that carbon steel and copper alloys in raw water are subject to flow blockage from fouling, loss of heat transfer effectiveness from fouling of heat transfer surfaces, and loss of material due to MIC. Carbon steel and copper alloy components exposed to raw water are identified as subject to loss of material due to erosion. Elastomer flexible collars in ambient air and exposed to borated water leakage are identified as subject to change in material properties from elevated temperature. The LRA identifies that the exposure of galvanized steel in air and to borated water leakage has no aging effects.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the HVAC auxiliary building:

- Boric Acid Corrosion Program (B.3.2)
- Open-Cycle Cooling Water System Program (B.3.5)
- One-Time Inspection Program (B.4.4)

* Systems Monitoring Program (B.3.17)
* Preventive Maintenance Program (B.3.18)

A description of these AMPs is provided in Appendix B of the LRA.

3.3.2.4.12.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-18, 3.3-1, and 3.3-2 for the HVAC auxiliary building. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-1, the applicant to clarify the discrepancy between Table 3.3-1, row 2 and Section B.3.17, "System Monitoring Program" regarding the aging effect/mechanisms of concern, and to provide additional information on the subject aging degradations. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.1 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff issued RAI 3.3-2 pertaining to the aging effects and AMP of the closure bolting in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.2 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-4, the applicant to provide the basis for not considering boric acid corrosion as an applicable aging effect for galvanized steel components included in Table 3.3-1, row 20. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.4 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-5, the applicant to clarify whether any of the auxiliary systems components for which the PM Program is credited may rely on the monitoring of leakage. In addition, the applicant was requested to provide a discussion of the operating history of these components to demonstrate that the applicable aging effects will be adequately managed prior to the loss of their intended functions. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.5 of this SER, and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the HVAC auxiliary building SSCs with the environments described in Tables 2.3-18, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the HVAC auxiliary building.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the HVAC auxiliary building:

- Boric Acid Corrosion Program (3.0.3.4)
- Open-Cycle Cooling Water System Program (3.0.3.7)
- One-Time Inspection Program (3.0.3.9)
- Systems Monitoring Program (3.0.3.11)
- Preventive Maintenance Program (3.0.3.12)

These AMPs are credited for managing the aging effects of components in several structures and systems and, therefore, are considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. These common AMPs are evaluated in Sections 3.0.3.4, 3.0.3.7, 3.0.3.9, 3.0.3.11, and 3.0.3.12 of this SER.

After evaluating the applicant's AMR for each of the components in the HVAC auxiliary building, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited AMPs that are appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the HVAC auxiliary building.

3.3.2.4.13 Heating Ventilation and Air Conditioning Control Room Area

3.3.2.4.13.1 Summary of Technical Information in the Application

The description of the HVAC control room area can be found in Section 2.3.3.13 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-19. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

<u>Aging Effects</u>

Table 2.3-19 of the LRA listed individual components in the HVAC control room area that are within the scope of LR and subject to AMR. The components include closure bolting, equipment frames and housings, flexible collars, flow orifices/elements, heating/cooling coils, valves, piping, tubing, and fittings.

SS and copper alloy components in indoor not-air-conditioned, containment air, air and gas, borated water leakage, and outdoor environments have no aging effects. The applicant stated that the applicable RNP environments do not promote concentration of contaminants or include exposure to aggressive chemical species. The applicant also stated that boric acid is not an aggressive chemical species for SS and copper alloys.

External surfaces of carbon steel components in indoor not-air-conditioned, containment air, and air and gas environments are not susceptible to corrosion if they are located in areas protected from the weather, not subjected to condensation, and not subjected to aggressive chemical attack.

For components made of elastomer (neoprene) material in warm and moist air, hardening, cracking and loss of strength due to elastomer degradation are identified as aging effect/mechanism.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the HVAC control room area:

- Open-Cycle Cooling Water System Program (B.3.5)
- Systems Monitoring Program (B.3.17)

A description of these AMPs is provided in Appendix B of the LRA.

3.3.2.4.13.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-19, 3.3-1, and 3.3-2 for the HVAC control room area. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-1, the applicant to clarify the discrepancy between Table 3.3-1, row 2 and Section B.3.17, "Systems Monitoring Program," regarding the aging effect/mechanisms for elastomer components included in numerous ventilation systems. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.1 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff issued RAI 3.3-3 related to the assumptions made in the discussion column of aging effects for carbon steel externally exposed to indoor not-air-conditioned, containment air, and air-gas environments. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this SER, and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the HVAC control room area SSCs with the environments described in Tables 2.3-19, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the HVAC control room area.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the HVAC control room area:

- Open-Cycle Cooling Water System Program (3.0.3.7)
- Systems Monitoring Program (3.0.3.12)

These AMPs are credited for managing the aging effects of components in several structures and systems and, therefore, are considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. These common AMPs are evaluated in Sections 3.0.3.7 and 3.0.3.12 of this SER.

After evaluating the applicant's AMR for each of the components in the HVAC control room area, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the HVAC control room area.

3.3.2.4.14 Heating Ventilation and Air Conditioning Fuel Handling Building

3.3.2.4.14.1 Summary of Technical Information in the Application

The description of the HVAC fuel handling building (FHB) can be found in Section 2.3.3.14 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-20. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Components of the HVAC FHB are described in Section 2.3.3.14 of the submittal as being within the scope of LR, and subject to an AMR. Table 2.3-20, on page 2.3-48 of the LRA, lists individual components of the system including closure bolting, ductor and fittings, equipment frames and housing, and flexible collars. Closure bolting and external surfaces of carbon steel components are identified as being subject to loss of material due to boric acid corrosion from exposure to borated water leaking from an adjacent system or component containing borated treated water. Elastomer flexible collars in ambient air and exposed to borated water leakage are identified as subject to change in material properties from elevated temperature. The LRA identifies that the galvanized steel in air and exposed to borated water leakage has no aging effects.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the HVAC FHB:

- Boric Acid Corrosion Program (B.3.2)
- System Monitoring Program (B.3.17)

A description of these AMPs is provided in Appendix B of the LRA.

3.3.2.4.14.2 Staff Evaluation

<u>Aging Effects</u>

The staff reviewed the information in Tables 2.3-20, 3.3-1 and 3.3-2 for the HVAC FHB. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-1, the applicant to clarify the discrepancy between Table 3.3-1, row 2 and Section B.3.17, "Systems Monitoring Program" regarding the aging effect/mechanisms of concern, and to provide additional information on the subject aging degradations. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.1 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff issued RAI 3.3-2 pertaining to the aging effects and AMP of the closure bolting in several of the auxiliary systems in the LRA. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.2 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-4, the applicant to provide the basis for not considering boric acid corrosion as an applicable aging effect for galvanized steel components included in Table 3.3-1, row 20. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.4 of this SER, and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects that result from contact of the HVAC FHB SSCs to the environments described in Tables 2.3-20, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the HVAC FHB.

<u>Aging Management Programs</u>

The applicant credited the following AMPs for managing the aging effects in the HVAC FHB:

- Boric Acid Corrosion Program (3.0.3.4)
- System Monitoring Program (3.0.3.12)

These AMPs are credited for managing the aging effects of components in several structures and systems and, therefore, are considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. These common AMPs are evaluated in Sections 3.0.3.4 and 3.0.3.12 of this SER.

After evaluating the applicant's AMR for each of the components in the HVAC FHB, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects for this system. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the HVAC FHB.

3.3.2.4.15 Fire Protection System

3.3.2.4.15.1 Summary of Technical Information in the Application

The description of the FP system can be found in Section 2.3.3.15 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-21. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

<u>Aging Effects</u>

LRA Table 2.3-21 lists individual components that are within the scope of LR and subject to an AMR. The components include bolting, pump casings, ductwork, fittings, sprinklers, valves, piping, tubings, fire hydrants, and filtration. Other items were identified during the responses to the RAIs, Strainers—Provides Filtration (RAI 2.3.3.15-9) and Flame Retardant Coatings—Loss of Material Due to Flaking (RAI 2.3.3.15-11). These items will be managed by the Preventive Maintenance AMP.

The LRA identifies that aluminum, SS, carbon steel, cast iron, copper, and flame retardant coatings are subject to loss of material due to general exterior corrosion, and carbon steel, low-alloy steel, and aluminum are subject to loss of material due to boric acid corrosion. Buried piping is subject to loss of material due to general pitting, crevice corrosion, and MIC. Doors and fire barrier penetration seals are subject to loss of material due to wear, hardening, and shrinkage due to weathering. Carbon steel and aluminum are subject to loss of material due to general pitting, crevice, and galvanic corrosion, MIC, and biofouling. Aluminum, bronze, brass, cast iron, and cast steel are subject to loss of material due to selective leaching.

The LRA does not identify any aging effects for carbon steel in areas protected from the weather, not subject to condensation, and not subjected to aggressive chemical attack; copper alloys, SS, and glass in air; and PVC piping in a buried environment.

<u>Aging Management Programs</u>

The following AMPs are utilized to manage aging effects in the FP system:

- Fire Protection Program (B.3.1)
- Boric Acid Corrosion Program (B.3.2)
- Fire Water System Program (B.3.7)
- Buried Piping and Tanks Surveillance Program (B.3.8)
- Buried Piping and Tanks Inspection Program (B.3.12)
- Structures Monitoring Program (B.3.15)
- Systems Monitoring Program (B.3.17)
- Preventive Maintenance Program (B.3.18)
- Selective Leaching of Materials Program (B.4.5)

A description of these AMPs is provided in Appendix B of the LRA.

3.3.2.4.15.2 Staff Evaluation

The staff reviewed the information in LRA Tables 2.3-21, 3.3-1, and 3.3-2 for the FP system. During its review, the staff requested additional information in order to complete its review of the fire protection program.

In RAIs 2.3.3.15-8, 2.3.3.15-9, and 2.3.3.15-10, sent out by letter February 11, 2003, the staff questioned why various portions of the FP system were not included within the scope of LR. In its response dated April 28, 2003, the applicant added several components to the scope of the FP system. The addition of these components did not result in the addition of material/ environment combinations or AMPs for the FP system. The staff's evaluation of the scope of the FP system is in Section 2.3.3.15 of this SER.

In RAI 3.3.2-2, sent by letter dated February 11, 2003, the staff questioned why the fire hydrants were included with carbon steel commodity group since hydrants are typically made of cast iron. In its response dated April 28, 2003, the applicant clarified that the cast iron of fire hydrants is included in the carbon steel material group, and was included in LRA Table 3.3-1, Item 20 of the LRA. The staff finds this response reasonable and acceptable.

On the basis of its review of the information provided in the LRA, and the additional information included in the applicant's response to the above RAIs, the staff finds that the aging effects identified for the FP SCs described in LRA Tables 2.3-21, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the FP system.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the FP system:

- Fire Protection Program
- Boric Acid Corrosion Program
- Fire Water System Program
- Buried Piping and Tanks Surveillance Program
- Buried Piping and Tanks Inspection Program
- Structures Monitoring Program
- Systems Monitoring Program
- Preventive Maintenance Program
- Selective Leaching of Materials Program

These AMPs are credited for managing the aging effects of components in several structures and systems and, therefore, are considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. These AMPs are evaluated in sections as indicated above in this SER.

On the basis of its review of the information provided in the LRA, the staff concludes that the above identified AMPs will effectively manage the aging effects of the FP system.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects from the materials and environments associated with the FP system.

3.3.2.4.16 Diesel Generator System

3.3.2.4.16.1 Summary of Technical Information in the Application

The description of the DG system can be found in Section 2.3.3.16 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-22. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Table 2.3-22 of the LRA listed individual system components that are within the scope of LR and subject to AMR. The components include HX shell, HX shell and water box cover, HX tube sheet, HX tubing, HX water box, regulators body/bonnet, heater shell, pumps, oil filters, oil strainers, air exhaust silencer, air intake silencer filters, air start strainers, air receiver tanks, tanks, flow orifices/elements, valves, piping, tubing, and fittings.

Carbon steel components in air and gas are identified as subject to loss of material due to general, pitting, and crevice corrosion. Carbon steel components are identified as being subject to loss of material from general corrosion in indoor not-air-conditioned and outdoor environments. Carbon steel in treated water (including steam) is identified as subject to loss of material due to general, pitting, and crevice corrosion. Carbon steel components in raw water are identified as being subject to loss of material from general, pitting, crevice, and galvanic corrosion, and MIC. Carbon steel in raw water and treated water (including steam) are identified as subject to loss of material from selective leaching. Carbon steel components in treated water (including steam) are identified as subject to loss of material due to galvanic corrosion. Copper alloys in treated water (including steam) are identified as subject to loss of material from crevice, pitting, and galvanic corrosion, and loss of heat transfer effectiveness from fouling of heat transfer surfaces. Copper alloys in raw water are identified as subject to loss of material from pitting, crevice, and galvanic corrosion, and MIC, as well as flow blockage from fouling and loss of heat transfer effectiveness from fouling of heat transfer surfaces. Copper alloys in air and gas are identified as subject to loss of material from pitting and crevice corrosion, and cracking from SCC. Copper alloys in raw water and treated water (including steam) are identified as subject to loss of material from selective leaching.

Elastomer hose and couplings are located in the internal environment of treated water (including steam); and the external environments of indoor not-air-conditioned. These components are identified as subject to change in material properties, cracking, and loss of material from various degradation mechanisms.

The RNP AMR assumed that external surfaces of carbon steel components in indoor not-air-conditioned, containment air, and air and gas environments would not be susceptible to corrosion if they were located in areas protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack (e.g., borated water leakage). The RNP AMR determined that SS and copper alloy components have no aging effects requiring management when exposed to indoor not-air-conditioned, containment air, air and gas, borated water leakage, and outdoor environments. The applicant stated that the applicable RNP environments do not promote concentration of contaminants or include exposure to aggressive chemical species, and that boric acid is not an aggressive chemical species for SS and copper alloys. The RNP AMR determined that carbon steel, SS, and copper alloys have no aging effects requiring management in a lubricating oil environment without water contamination.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the DG system.

- Open-Cycle Cooling Water System Program (B.3.5)
- Closed-Cycle Cooling Water System Program (B.2.5)
- One-Time Inspection Program (B.4.4)
- Selective Leaching of Materials Program (B.4.5)
- Systems Monitoring Program (B.3.17)
- Preventive Maintenance Program (B.3.18)

A description of these AMPs is provided in Appendix B of the LRA.

3.3.2.4.16.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-22, 3.3-1, and 3.3-2 for the DG system. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff issued RAI 3.3-3 related to the assumptions made in the discussion column of aging effects for carbon steel externally exposed to indoor not-air-conditioned, containment air, and air-gas environments. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-5, the applicant to clarify whether any of the auxiliary systems components for which the PM Program is credited may rely on the monitoring of leakage. In addition, the applicant was requested to provide a discussion of the operating history of these components to demonstrate that the applicable aging effects will be adequately managed prior to the loss of their intended functions. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.5 of this SER, and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds the aging effects that result from contact of the DG system SSCs to the environments described in Tables 2.3-22, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the DG system.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the DG system:

- Open-Cycle Cooling Water System Program (3.0.3.7)
- Closed-Cycle Cooling Water System Program (3.0.3.8)
- One-Time Inspection Program (3.0.3.9)
- Selective Leaching of Materials Program (3.0.3.10)
- Systems Monitoring Program (3.0.3.11)
- Preventive Maintenance Program (3.0.3.12)

These AMPs are credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Sections 3.0.3.7, 3.0.3.8, 3.0.3.9, 3.0.3.11, and 3.0.3.12, respectively, of this SER.

After evaluating the applicant's AMR for each of the components in the DG system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the DG system.

3.3.2.4.17 Dedicated Shutdown Diesel Generator

3.3.2.4.17.1 Summary of Technical Information in the Application

The description of the DS DG can be found in Section 2.3.3.17 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-23. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Table 2.3-23 of the LRA listed individual system components that are within the scope of LR and subject to AMR. The components include exhaust air silencer, air filter, tanks, heater, pumps, oil cooler shell, oil cooler tubing and channels, oil cooler channel and shell, oil cooler tubing and fins, oil filter, oil strainer, radiator tubing, radiator waterbox, ductwork and fittings, and valves, piping, tubing, and fittings.

SS components in, indoor not-air-conditioned environments are identified as subject to loss of material from pitting and crevice corrosion, and MIC. SS valves, piping, tubing, and fittings in indoor not-air-conditioned environments and are identified as subject to cracking from SCC.

Carbon steel components in indoor not-air-conditioned environments are identified as subject to loss of material from general and galvanic corrosion, and MIC. Carbon steel components in outdoor environments are identified as subject to loss of material from general corrosion and loss of heat transfer effectiveness from fouling of heat transfer surfaces. Carbon steel components in air and gas are identified as subject to loss of material from general and galvanic corrosion, and MIC. Carbon steel components in treated water (including steam) are identified as subject to general, pitting, and crevice corrosion. Carbon steel components in treated water (including steam) are identified as subject to loss of material from galvanic corrosion and loss of heat transfer effectiveness from fouling of heat transfer surfaces. Buried carbon steel piping and fittings are identified as subject to loss of material from general, crevice, and pitting corrosion, and MIC.

Copper alloys in indoor not-air-conditioned or outdoor environments are identified as subject to loss of material from pitting and crevice corrosion. Copper alloys in treated water (including steam) are identified as subject to loss of material from selective leaching. Copper alloys are identified as subject to loss of material from pitting and crevice corrosion in air and gas environments. Copper alloys in treated water (including steam) are identified as subject to loss of material from crevice, pitting, and loss of heat transfer effectiveness from fouling of heat transfer surfaces.

Elastomer hose and couplings are located in the internal environments of lubricating oil and treated water (including steam), and the external environments of indoor not-air-conditioned. These components are identified as being subject to change in material properties, cracking, and loss of material from various degradation mechanisms.

The RNP AMR assumed that external surfaces of carbon steel components in indoor not-air-conditioned, containment air, and air and gas environments would not be susceptible to corrosion if they were protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack (e.g., borated water leakage). The RNP AMR assumed that external surfaces of SS and copper alloys components in indoor not-air-conditioned, containment air, air and gas, borated water leakage, and outdoor environments would not have aging effects requiring management. The applicant stated that the applicable environments do not promote concentration of contaminants or include exposure to aggressive chemical species, and that boric acid is not an aggressive chemical species for SS and copper alloys. The RNP AMR determined that carbon steel, SS, and copper alloys have no aging effects requiring management in a lubricating oil environment without water contamination.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the DS DG system:

- Closed-Cycle Cooling Water System Program (B.2.5)
- Systems Monitoring Program (B.3.17)
- Preventive Maintenance Program (B.3.18)
- Buried Piping and Tanks Inspection Program (B.3.8)

A description of these AMPs is provided in Appendix B of the LRA.

3.3.2.4.17.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-23, 3.3-1, and 3.3-2 for the DS DG. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff issued RAI 3.3-3 related to the assumptions made in the discussion column of aging effects for carbon steel externally exposed to indoor not-air-conditioned, containment air, and air-gas environments. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-5, the applicant to clarify whether any of the auxiliary systems components for which the PM Program is credited may rely on the monitoring of leakage. In addition, the applicant was requested to provide a discussion of the operating history of these components to demonstrate that the applicable aging effects will be adequately managed prior to the loss of their intended functions. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.5 of this SER, and is characterized as resolved.

In LRA Tables 2.3-23 and 3.3-2 for DS DG, rows 12, 13, and 23 are identified as AMR links for SS valves, piping, tubing, and fittings. In row 12, the applicant identified loss of material from pitting and crevice corrosion and MIC as aging effects for the components exposed to indoor air-conditioned, indoor not-air-conditioned, containment air, borated water leakage, and outdoor environments. In row 13, the applicant identified cracking from SCC as an aging effect requiring management for the above components exposed to indoor not-air-conditioned and outdoor environments. In row 23, for the seemingly identical component/material/environment combination as in row 12, however, the applicant has identified no aging effects requiring management. The staff discussed the issues with the applicant.

The applicant explained that the air and gas environments in rows 12 and 13 include the potential for wetting of SS by untreated water, which is the genesis of the potential aging effects. The environment in row 23, on the other hand, is considered a reasonably dry one which results in no potential aging effects for SS. For specific examples, the applicant stated that the diesel component involved in Table 3.3-2, rows 12 and 13, is a single SS drain valve on the DSD air start receiver. The compressed air used for starting the DSD has no dryer, so the conditions exist for a buildup of untreated water inside the air receiver and drain piping. The internal surface of the valve is, therefore, subjected to wetting. The external surface of the same valve is subjected to condensation and was conservatively modeled as exposed to a wetted environment. The applicant also stated that an external surface of a SS check valve in the lube oil circulating pump discharge is not exposed to a wetted environment and is, therefore, referred to in row 23. Both the diesel air start subsystem and diesel lube oil subsystem are located inside the DSD enclosure. The applicant further stated that the internal environment of the SS check valve in the lube oil circulating pump discharge for DSD diesel is included in LRA Table 3.3-2, row 22. It too has no aging effects, and is not related to the air and gas environments described above. The staff finds the above information satisfactorily confirms the AMR results for the SS valves, piping, tubing, and fittings in row 12, 13, and 23, and is, therefore, acceptable. However, the applicant is requested to provide the above information under oath and affirmation. By letter dated August 14, 2003, the applicant provided the requested information. Confirmatory Item 3.3.2.4.17-1 is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to RAIs 3.3-3 and 3.3-5, the staff finds that the aging effects that result from contact of the DS DG SSCs to the environments described in Tables 2.3-23, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the DS DG.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the DS DG.

- Closed-Cycle Cooling Water System Program (3.0.3.8)
- Systems Monitoring Program (3.0.3.11)
- Preventive Maintenance Program (3.0.3.12)
- Buried Piping and Tanks Inspection Program (3.3.2.3.4)

Three AMPs are credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Sections 3.0.3.8, 3.0.3.11, 3.0.3.12, and 3.3.2.37 of this SER, respectively.

After evaluating the applicant's AMR for each of the components in the DS DG, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effects.

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the DS DG.

3.3.2.4.18 EOF/TSC Security Diesel Generator

3.3.2.4.18.1 Summary of Technical Information in the Application

The description of the EOF/TSC security DG can be found in Section 2.3.3.18 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA Table 2.3-24. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Table 2.3-24 of the LRA listed individual system components that are within the scope of license renewal and subject to AMR. The components include ductwork and fittings, intake filters, exhaust silencers, heaters, radiator, and valves, piping, tubing, and fittings.

Carbon steel components in indoor not-air-conditioned environments are identified as subject to loss of heat transfer effectiveness from fouling of heat transfer surfaces. Carbon steel components in outdoor environments are identified as subject to loss of material from general corrosion. Carbon steel components in treated water (including steam) are identified as subject to general, pitting, and crevice corrosion. Carbon steel components in treated water (including steam) are identified as subject to loss of material from loss of heat transfer effectiveness from fouling of heat transfer surfaces.

Copper alloys in treated water (including steam) are identified as subject to loss of material from selective leaching. Copper alloys in treated water (including steam) are subject to loss of material from crevice, and pitting corrosion.

Elastomer hose and couplings are located in the internal environments of lubricating oil and treated water (including steam), and the external environments of indoor not-air-conditioned. These components are identified as being subject to change in material properties, cracking, and loss of material from various degradation mechanisms.

The RNP AMR assumed that external surfaces of carbon steel components in indoor not-air-conditioned, containment air, and air and gas environments would not be susceptible to corrosion if they were protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack (e.g., borated water leakage). The RNP AMR assumed that external surfaces of SS and copper alloys components in indoor not-air-conditioned, containment air, air and gas, borated water leakage, and outdoor environments would not have aging effects requiring management. The applicant stated that the applicable environments do not promote concentration of contaminants or include exposure to aggressive chemical species, and that boric acid is not an aggressive chemical species for SS and copper alloys. The RNP AMR determined that carbon steel, SS, and copper alloys have no aging effects requiring management in a lubricating oil environment without water contamination. The RNP AMR also determined that galvanized steel ductwork and fittings would experience no age-related degradation requiring management in indoor not-air-conditioned, containment air, and borated water leakage environments.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the EOF/TSC security DG.

- Closed-Cycle Cooling Water System Program (B.2.5)
- Systems Monitoring Program (B.3.17)
- Preventative Maintenance Program (B.3.18)

A description of these AMPs is provided in Appendix B of the LRA.

3.3.2.4.18.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-24, 3.3-1, and 3.3-2 for the EOF/TSC security

DG. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff issued RAI 3.3-3 related to the assumptions made in the discussion column of aging effects for carbon steel externally exposed to indoor not-air-conditioned, containment air, and air-gas environments. The staff's evaluation of the applicant's response is documented in Section 3.3.2.5.3 of this SER, and is characterized as resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff finds the aging effects that result from contact of the EOF/TSC security DG SSCs to the environments described in Tables 2.3-24, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the EOF/TSC security DG.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the EOF/TSC security DG:

- Closed-Cycle Cooling Water System Program (3.0.3.8)
- Systems Monitoring Program (3.0.3.11)
- Preventative Maintenance Program (3.1.3.12)

These AMPs are credited for managing the aging effects of several components in other structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Sections 3.0.3.8, 3.1.3.11, and 3.0.3.12, respectively, of this SER.

After evaluating the applicant's AMR for each of the components in the EOF/TSC security DG, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the EOF/TSC security DG.

3.3.2.4.19 Fuel Oil System

3.3.2.4.19.1 Summary of Technical Information in the Application

The description of the fuel oil (FO) system can be found in Section 2.3.3.19 of this SER. The passive, long-lived components in this system that are subject to an AMR are identified in LRA

Table 2.3-25. The components, aging effects, and AMPs are provided in LRA Tables 3.3-1 and 3.3-2.

Aging Effects

Components of the FO system are described in Section 2.3.3.19 of the submittal as within the scope of LR and subject to an AMR. Table 2.3-25, on pages 2.3-58 and 2.3-59 of the LRA, lists individual components of the system including diesel fire pump FO tank, diesel oil storage tank vent filter, DS diesel (DSD) FO day tank, DSD FO priming pumps, DSD FO pumps, DSD FO tank, EDG day tank vent filters, EDG FO day tanks, EDG FO duplex filters, EDG FO hand priming pumps, EDG FO storage tank, EOF DG FO day tank, EOF DG FO pump, EOF/TSC main storage tank, flow orifices/elements, FO transfer pumps, Unit 1 IC turbine tanks, and valves, piping, tubing, and fittings.

The LRA identifies carbon steel, copper alloys and SS in indoor not-air-conditioned, and outdoor environments are identified as subject to loss of material due to general, pitting, and crevice corrosion, and/or MIC for carbon steel; while for copper alloys and SS components in the FO system, the aging mechanisms are limited to pitting and crevice corrosion. SS, carbon steel, and copper alloys in FO (with potential water contamination) are subject to loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling for carbon steel and due to MIC only for copper alloys and SS components. The LRA also identifies SS components in indoor not-air-conditioned, and outdoor environments as being subject to loss of material due to pitting corrosion, crevice corrosion, and MIC, and cracking from SCC. SS components in, indoor not-air-conditioned and outdoor environments are identified as subject to loss of material from pitting and crevice corrosion and MIC. The applicant stated that boric acid is not an aggressive chemical species for SS. The RNP AMR assumed that external surfaces of SS components in indoor not-air-conditioned and outdoor environments would not have aging effects requiring management.

The applicant has provided additional information related to the aging effects of the external surfaces of SS components/environments combinations in the response to Confirmatory Item 3.3.2.4.19-1, in letter RNP-RA/03-0094, dated August 14, 2003.

Elastomers and miscellaneous piping components are identified as subject to change in material properties, hardening, cracking, and loss of strength due to elastomer degradation and loss of material due to various degradation mechanisms from exposure to ambient air and gas, treated water (including steam), and borated water leakage. Buried carbon steel is subject to loss of material due to general, crevice corrosion, and pitting corrosion, and MIC. Exposure of SS and copper alloy components to indoor not-air-conditioned environments, and fiberglass reinforced polyester components in the buried and outdoor environments, have no aging effects.

Aging Management Programs

The following AMPs are utilized to manage aging effects in the FO system:

- One-Time Inspection Program (B.4.4)
- Systems Monitoring Program (B.3.17)
- Preventive Maintenance Program (B.3.18)

- Buried Piping and Tanks Surveillance Program (B.3.8)
- Aboveground Carbon Steel Tanks Program (B.3.9)
- Fuel Oil Chemistry Program (B.3.10)

A description of these AMPs is provided in Appendix B of the LRA.

3.3.2.4.19.2 Staff Evaluation

Aging Effects

The staff reviewed the information in Tables 2.3-25, 3.3-1, and 3.3-2 for the FO system. During its review, the staff determined that additional information was needed to complete its review.

By letter dated February 11, 2003, the staff issued RAI 3.3-3 related to the assumptions made in the discussion column of aging effects for carbon steel externally exposed to indoor not-air-conditioned, containment air, and air-gas environments. The staff's evaluation of the applicant's response is documented in Section 3.3.2.3.3 of this SER, and is characterized as resolved.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-5, the applicant to clarify whether any of the auxiliary systems components for which the PM Program is credited may rely on the monitoring of leakage. In addition, the applicant was requested to provide a discussion of the operating history of these components to demonstrate that the applicable aging effects will be adequately managed prior to the loss of their intended functions. The staff's evaluation of the applicant's response is documented in Section 3.3.2.3.5 of this SER, and is characterized as resolved.

In LRA Tables 2.3-25, and 3.3-2 for the FO system, rows 12, 13, and 23 are identified as AMR links for SS valves, piping, tubing, and fittings. In row 12, the applicant identified loss of material from pitting and crevice corrosion and MIC as aging effects for the components exposed to indoor air-conditioned, indoor not-air-conditioned, containment air, borated water leakage, and outdoor environments. In row 13, the applicant identified cracking from SCC as an aging effect requiring management for the above components exposed to indoor not-air-conditioned and outdoor environments. In row 23, for the seemingly identical component/material/environment combination as in row 12, however, the applicant has identified no aging effects requiring management. The staff discussed the issues with the applicant.

The applicant explained that the air and gas environments in rows 12 and 13 include the potential for wetting of SS by untreated water, which is the genesis of the potential aging effects. In row 23, the environment is considered a reasonably dry environment which results in no potential aging effects for SS. For the FO system, it has a SS valve and instrumentation tubing, valves, and fittings that are conservatively modeled in a wetted outdoor environment. The FO tank level instrumentation is located outdoors and has components that are near the ground. Therefore, it was conservatively evaluated as having a potentially wetted external environment. These items account for Table 3.3-2, rows 12 and 13, referenced for valves, piping, tubing, and fittings from Table 2.3-25. There are also other SS piping components (indoor not-air-conditioned) that are not in a potentially wetted environment and have no potential aging effects associated with its external surface. These latter items are referring to

Table 3.3-2, row 23, which have no aging effects.

On the basis of its review, the staff finds the applicant's response acceptable because the applicant has clarified the issues clearly. However, the applicant was requested to provide the above information under oath and affirmation. By letter dated August 14, 2003, the applicant provided the requested information. Confirmatory Item 3.3.2.4.19-1 is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to RAIs 3.3-3 and 3.3-5, the staff finds that the aging effects that result from contact of the FO system SSCs to the environments described in Tables 2.3-25, 3.3-1, and 3.3-2 are consistent with industry experience for these combinations of materials and environments. Therefore, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with the components in the FO system.

Aging Management Programs

The applicant credited the following AMPs for managing the aging effects in the FO system:

- One-Time Inspection Program (3.0.3.9)
- Systems Monitoring Program (3.0.3.11)
- Preventive Maintenance Program (3.0.3.12)
- Buried Piping and Tanks Surveillance Program (3.3.2.3.4)
- Aboveground Carbon Steel Tanks Program (3.3.2.3.5)
- Fuel Oil Chemistry Program (3.3.2.3.6)

With the exception of the Buried Piping and Tanks Surveillance Program, the Aboveground Carbon Steel Tanks Program, and the Fuel Oil Chemistry Program, these AMPs are credited for managing the aging effects of components in several structures and systems and, therefore, are considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. These common AMPs are evaluated in Sections 3.0.3.9, 3.0.3.11, and 3.0.3.12 of this SER. The Buried Piping and Tanks Surveillance Program, the Aboveground Carbon Steel Tanks Program, and the Fuel Oil Chemistry Program have been evaluated and found to be appropriate for this system. The Buried Piping and Tanks Surveillance Program, the Aboveground Carbon Steel Tanks Program, and the Fuel Oil Chemistry Program are discussed in Sections 3.3.2.3.4, 3.3.2.3.5, and 3.3.2.3.6 of this SER, respectively.

The staff asked several RAIs related to the Buried Piping and Tanks Surveillance Program (RAIs B.3.8-1 through B.3.8-9), the Aboveground Carbon Steel Tanks Program (RAIs B.3.9-1 through B.3.9-6), and the Fuel Oil Chemistry Program (RAIs B.3.10-1 through B.3.10-10). All RAIs have been satisfactorily resolved. The details of the staff's evaluation of these RAIs are discussed in Sections 3.3.2.3.4, 3.3.2.3.5, and 3.3.2.3.6 of this SER, respectively.

After evaluating the applicant's AMR for each of the components in the FO system, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in LRA Table 3.3-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the FO system.

3.3.2.4.19.3 Conclusions

On the basis of its review, the staff concludes that, the applicant has adequately identified the aging effects, and the AMPs credited for managing the aging effects, of the auxiliary system plant specific components described in Sections 3.3.2.4.1 through 3.3.2.4.19, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR Supplement program description and concludes that it provides an adequate program description of the AMPs credited for managing aging of the auxiliary system plant specific components, as required by 10 CFR 54.21(d).

3.3.2.5 General AMR Issues

This section discusses the staff's evaluation of general AMR issues that are applicable to components in several auxiliary systems included in Section 3.3 of the LRA.

3.3.2.5.1 Wear Degradation of Elastomer Components

Numerous ventilation systems, including RAB HVAC, control room area HVAC, FHB HVAC systems, the containment purge system, and the rod drive cooling system discussed in Section 2.3 of the LRA, include elastomer components. Normally these systems contain elastomer materials in duct seals, flexible collars between ducts and fans, rubber boots, etc. For some plant designs, elastomer components are used as vibration isolators to prevent transmission of vibration and dynamic loading to the rest of the system. In Table 3.3-1, row 2, of the LRA, the applicant identified the aging effects of hardening, cracks, and loss of strength due to elastomer degradation and credited the System Monitoring Program, AMP B.3.17, for managing these aging effects. In the discussion column of that row, the applicant stated that loss of material due to wear was not identified as an aging mechanism for elastomer components; however, wear also would be managed by AMP B.3.17. However, the staff noted that AMP B.3.17 did not include wear as one of the aging mechanisms of concern.

By letter dated February 11, 2003, the staff requested, in RAI 3.3-1, the applicant to clarify the discrepancy between Table 3.3-1, row 2 and AMP B.3.17 regarding the aging effects/mechanisms of concern. In addition, the applicant was requested to provide the frequency of the inspection described in AMP B.3.17 for the applicable elastomer components including a discussion of the operating history to demonstrate that the applicable aging degradations will be detected prior to the loss of their intended function.

In its response dated April 28, 2003, the applicant stated that wear was not identified as an aging effect for these components. However, the RNP AMP will be enhanced to ensure that loss of material due to wear is specifically included as an aging effect/mechanism identified in the system walkdown checklist. This will ensure that this effect/mechanism will be managed consistent with GALL VII.F1.1-c, VII.F2.1-c, VII.F3.1-c, and VII.F4.1-c.

The applicant further stated that walkdowns are typically scheduled and performed so the entire system is fully walked down within one operating cycle. The Systems Monitoring Program is designed to detect aging effects prior to structure or component failure. As an example, system walkdowns identified degradation of flexible connections between the fan unit housing for the containment recirculating cooling units and the adjacent ductor. This degradation was characterized by missing/torn flexible material. For this degradation, the material was replaced by a different material. This example demonstrates the effectiveness of the current site program in identifying degradation prior to loss of component intended function. Implementation of program enhancements identified during the LR process will serve to further increase program effectiveness. The enhancements are generally described in LRA B.3.17. A more detailed description of several of the relevant program attributes is discussed in the RNP response to RAI B.3.17-1.

On the basis of its review, the staff finds the applicant's response adequate and acceptable because (1) the applicant's response clarifies that in addition to the aging effects of hardening, cracks, and loss of strength, the aging effects of wear will be managed by the enhanced Systems Monitoring Program and (2) the applicant's response demonstrates that with the scheduled system walkdown, the applicable aging degradations of these elastomer components will be detected prior to the loss of their intended function.

3.3.2.5.2 Closure Bolting

For the closure bolting in several of the auxiliary systems included in Table 3.3-1, row 13, of the LRA, the applicant identified loss of material due to boric acid corrosion as an applicable aging effect. In the discussion column of that row, the applicant stated that loss of material due to boric acid corrosion can lead to loss of mechanical closure integrity of closure bolting. The applicant also stated that the aging mechanism is loss of mechanical closure integrity from loss of material due to aggressive chemical attack. The applicant credited the Boric Acid Corrosion Program (AMP B.3.2) for managing this aging effect. The staff also noted that in Table 3.3-1, row 23, of the LRA, the applicant has identified loss of material due to general corrosion, crack initiation, and growth due to cyclic loading and SCC as the applicable aging effects for closure bolting in auxiliary systems. The applicant credited the Bolting Integrity Program (AMP B.3.4) for managing these aging effects. However, the staff noted that, with the exception of closure bolting in CVCS, the applicant did not identify these aging effects included in Table 3.3-1, Row Number 23 for the closure bolting in auxiliary systems. By letter dated February 11, 2003, the staff requested, in RAI 3.3-2, the applicant to explain why the other aging effects/mechanisms of concern identified in AMP B.3.4 and row 23 of Table 3.3-1 are not applicable to the closure bolting in other auxiliary systems and why AMP B.3.4 is not used to manage aging effects for the closure bolting in these auxiliary systems.

In its response dated April 28, 2003, the applicant stated that the RNP methodology treats pressure boundary bolting as a subcomponent except in those cases where it must be individually evaluated for AMR. If a valve and its pressure boundary bolting are considered susceptible to an aging effect, and the same AMP would be applied to both, then the bolting would generally be treated as part of the valve. Within this constraint, the listing of aging effects in AMP B.3.4 is an aggregate set applicable to bolting in the scope of LR. The applicant also stated that, relative to Table 3.3-1, row 23, aging management of bolting for SCC was specified only in those instances where susceptible bolting was identified. SCC of bolting requires susceptible material (generally associated with bolts with minimum yield greater than

150 ksi), and a design review found a single incidence of susceptible auxiliary system pressure boundary bolting in the scope of LR. This resulted in the listing of SCC for the CVCS closure bolting in Table 3.3-1, row 23, and AMP B.3.4 as the applicable AMP.

The applicant further stated that, in addition to boric acid corrosion and SCC, AMP B.3.4 identifies stress relaxation and wear as applicable aging effects. The instance of stress relaxation noted in AMP B.3.4 is based on site OE and is specific to the RCP flanges. Stress relaxation has been evaluated not to be applicable to RNP auxiliary systems based on system operating temperatures, and loss of preload is considered to be a design issue, not an aging effect. Similarly, the applicant stated that the potential for wear was based on a review of Generic Technical Report WCAP-14575-A regarding RCS Class 1 closures, and is not considered applicable to auxiliary systems. Hence, the applicant concluded that neither of these aging effects was included in LRA Table 3.3-1.

On the basis of its review, the staff finds the applicant's response acceptable because (1) the applicant treated the pressure boundary bolting as part of the component being considered and applied the same AMP to both, and (2) the applicant further stated that the listing of aging effects in AMP B.3.4 is an aggregate set applicable to bolting in the scope of LR in general, and the listed stress relaxation and wear aging effects are not considered applicable to the auxiliary systems

3.3.2.5.3 External Environments

In Table 3.3-2, row 19, of the LRA, the applicant did not identify aging effects for carbon steel externally exposed to indoor not-air-conditioned, containment air, and air/gas environments. In the discussion column of that row, the applicant stated that its AMR methodology assumed that external surfaces of carbon steel components would not be susceptible to corrosion if they were located in areas protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack (e.g., borated water leakage). By letter dated February 11, 2003, the staff requested, in RAI 3.3-3, the applicant to verify that the assumption is appropriate for the combination of materials and environments listed in Table 3.3-2, row 19, of the LRA. In its response dated April 28, 2003, the applicant stated that LRA Table 3.3-2, row 19, represents carbon steel components that are indoor, not exposed to weather, not prone to condensation, and therefore are not considered to be in a moist environment. The applicant further stated that in the absence of an aggressive chemical environment (i.e., boric acid leakage), significant corrosion of carbon steel will not occur without the presence of moisture.

On the basis of its review, the staff finds the applicant's response acceptable because the information provided by the applicant clarified that the subject carbon steel components are not exposed to moist environments and are not subjected to aggressive chemical attack and, therefore, are not susceptible to corrosion.

3.3.2.5.4 Boric Acid Corrosion for Galvanized Steel Component

In Table 3.3-2, row 20, of the LRA, the applicant stated that the galvanized steel components would experience no age-related degradation requiring management in the environments of indoor not-air-conditioned, containment air, and borated water leakage. By letter dated February 11, 2003, the staff requested, in RAI 3.3-4, the applicant to provide a basis for not considering boric acid corrosion as an applicable aging effect for these galvanized steel components.

In its response dated April 28, 2003, the applicant stated that the aging effects and AMRs applicable to galvanized steel components exposed to borated water leakage were revisited. The applicant stated that based on the potential for boric acid leakage to concentrate to the point where degradation of the galvanized steel coating could occur, it was determined now that galvanized steel components would be susceptible to aging effects from boric acid leakage as are carbon or low-alloy steels. The applicant further stated that for these galvanized steel components, the aging effect was changed to "loss of material," and the corresponding mechanism was changed to "aggressive chemical attack." The Boric Acid Corrosion Program will be used to manage loss of material due to aggressive chemical attack for the external surfaces of such components.

On the basis of its review, the staff finds the applicant's response acceptable because the applicant has adequately identified the aging effect of loss of material due to boric acid corrosion and has credited the Boric Acid Corrosion Program to manage the aging effect. The staff has evaluated the Boric Acid Corrosion Program and has found it to be acceptable for managing the subject aging effect as described in Section 3.0.3.4 of this SER.

3.3.2.5.5 Monitoring of Leakage Detection

In Table 3.3-1, row 5, of the LRA, the applicant credited the PM Program for managing aging effects for the internal surfaces of numerous components in auxiliary systems. The staff noted that in Appendix B.3.18, "Preventive Maintenance Program," under *Monitoring and Trending*, the applicant included leakage as an example of technique and a parameter monitored. By letter dated February 11, 2003, the staff requested, in RAI 3.3-5, the applicant to clarify whether any of these auxiliary systems components, including DG systems, for which the Preventive Maintenance Program is credited may rely on the monitoring of leakage. In addition, the staff requested the applicant to provide a discussion of the operating history of these components to demonstrate that the applicable aging effects will be adequately managed prior to the loss of their intended functions. The staff's concern is that the presence of leakage from a component might signal the loss of its capability in performing its intended function as a pressure boundary.

In its response dated April 28, 2003, the applicant stated that expected leakage from systems typically consists of flange or packing leaks. Throughwall leaks are not expected and would require corrective action, not trending. During PM activities, equipment is opened and is externally and internally inspected for degradation. Many of the repetitive PM procedures and work packages require general surface conditions to be inspected. Leakage represents an extreme point of degradation and would not typically be relied upon as the sole attribute of the monitoring program. The applicant listed some examples of monitoring techniques/trend parameters for various plant equipment types as (1) helium leak detection for main condenser tubes and various valves and flanges; (2) plant walkdown to look for various performance problems, such as dump valves not reset, steam trap leaks, valve leakthrough to the condenser, miscellaneous steam leaks, oscillating feedwater level control, etc.; and (3) visual examinations for coating failures, corrosion, cracking, erosion, leaking and physical condition, mechanical damage, loose or missing hardware, etc. Again, the applicant stressed that leakage is not the sole parameter monitored, but might help indicate cracking or degradation. The result may be more careful or frequent inspections. Also, leakage would be an indication that additional and more directed inspections may be needed to ascertain the extent of the condition. The applicant further stated that leakage does not necessarily mean that the system intended function cannot be achieved.

On the basis of its review, the staff finds the applicant's response acceptable because the applicant's maintenance procedure, including monitoring/trending of various plant parameters, will adequately manage the applicable aging effects of these components prior to the loss of their intended function.

3.3.2.5.6 Conclusions

The staff has evaluated the general AMR issues discussed above and concludes that, on the basis of the staff's review of the LRA and the applicant's responses to the staff's RAIs, the applicant has adequately considered (1) wear degradation of elastomer components, (2) closer bolting, (3) external environments, (4) boric acid corrosion for galvanized steel componenets, and (5) monitoring of leakage detection, in its aging management evaluations, and that the components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program description and concludes that the UFSAR Supplement provides an adequate description of the AMP credited for managing aging of the above AMR issues to satisfy 10 CFR 54.21(d).

3.3.3 Evaluation Findings

The staff has reviewed the information in Section 3.3 of the LRA. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the auxiliary systems, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation. The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited for managing aging effects, as required by 10 CFR 54.21(d).

3.4 Steam and Power Conversion Systems

This section addresses the aging management of the components of the steam and power conversion systems group. The systems that make up the steam and power conversion systems group are described in the following SER sections:

- Turbine System (2.3.4.1)
- Electro-Hydraulic Control System (2.3.4.2)
- Turbine Generator Lube Oil System (2.3.4.3)
- Extraction Steam System (2.3.4.4)
- Main Steam (2.3.4.5)
- Steam Generator Blowdown (2.3.4.6)
- Steam Cycle Sampling (2.3.4.7)
- Feedwater (2.3.4.8)
- Auxiliary Feedwater (2.3.4.9)
- Condensate (2.3.4.10)

- Steam Generator Chemical Addition (2.3.4.11)
- Circulating Water (2.3.4.12)

As discussed in Section 3.0.1 of this SER, the components in each of these steam and power conversion systems are included in one of two LRA tables. LRA Table 3.4-1 consists of steam and power conversion systems components that are evaluated in the GALL Report, and steam and power conversion systems components that were not evaluated in the GALL Report, but the applicant has determined can be managed using a GALL AMR and associated AMP. LRA Table 3.4-2 consists of steam and power conversion systems components that are not evaluated in the GALL Report.

3.4.1 Summary of Technical Information in the Application

In LRA Section 3.4, the applicant described its AMRs for the steam and power conversion systems group at RNP. The passive, long-lived components in these systems that are subject to an AMR are identified in LRA Tables 2.3-26, 2.3-27, 2.3-28, 2.3-29, 2.3-30, 2.3-31, and 2.3-32, and in paragraph 2.3.4.7.

The applicant's AMRs included an evaluation of plant-specific and industry OE. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify aging effects that require management. These reviews concluded that the aging effects requiring management based on RNP OE were consistent with aging effects identified in the GALL Report. The applicant's review of industry OE included a review of OE through December 2001. The results of this review concluded that aging effects requiring management based on industry operating experience were consistent with aging effects identified in the GALL Report. The applicant's ongoing review of plant-specific and industry-wide OE is conducted in accordance with the RNP Corrective Action and Operating Experience Programs.

3.4.2 Staff Evaluation

In Section 3.4 of the LRA, the applicant describes its AMR for the steam and power conversion systems at RNP. The staff reviewed Section 3.4 to determine whether the applicant has provided sufficient information to demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation, in accordance with the requirements of 10 CFR 54.21(a)(3), for the steam and power conversion systems components that are determined to be within the scope of LR and subject to an AMR.

The systems that make up the steam and power conversion systems group are (1) turbine system, (2) electrohydraulic control (EHC), (3) turbine generator lube oil, (4) extraction steam, (5) main steam, (6) SG blowdown, (7) steam cycle sampling, (8) feedwater, (9) AFW, (10) condensate, (11) SG chemical addition, and (12) circulating water.

The applicant referenced the GALL Report in its AMR. The staff has previously evaluated the adequacy of the aging management of steam and power conversion systems components for LR as documented in the GALL Report. Thus, the staff did not repeat its review of the matters described in the GALL Report, except to ensure that the material presented in the LRA was applicable, and to verify that the applicant had identified the appropriate programs as described and evaluated in the GALL Report. The staff evaluated those aging management issues recommended for further evaluation in the GALL Report. The staff also reviewed aging management information submitted by the applicant that was different from that in the GALL Report or was not addressed in the GALL Report.

Table 3.4-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.4 that are addressed in the GALL Report.

Table 3.4-1

Staff Evaluation Table for RNP Steam and Power Conversion Systems Components Evaluated in the GALL Report

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
(1) Piping and fittings in main feedwater line, steam line and AFW piping (PWR only)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	10 CFR 54.21(c)(1)(i) Analyses remain valid	Consistent with GALL. GALL recommends further evaluation (see staff evaluation in Section 3.4.2.2.1)
(2) Piping and fittings, valve bodies and bonnets, pump casings, tanks, tubes, tubesheets, channel head and shell (except main steam system)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Chemistry Program and One-Time Inspection Program	Consistent with GALL. GALL recommends further evaluation (see staff evaluation in Section 3.4.2.2.2)
(3) Auxiliary feedwater piping	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling	Plant specific	Not applicable. AFW piping at RNP not exposed to untreated water from a backup water supply	GALL recommends further evaluation (see staff evaluation in Section 3.4.2.2.3)

(4) Oil coolers in AFW system (lubricating oil side possibly contaminated with water)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion, and MIC	Plant specific	Preventive Maintenance Program	GALL recommends further evaluation (see staff evaluation in Section 3.4.2.2.5)
(5) External surface of carbon steel components	Loss of material due to general corrosion	Plant specific	Systems Monitoring	Consistent with GALL. GALL recommends further evaluation (see staff evaluation in Section 3.4.2.2.4)
(6) Carbon steel piping and valve bodies	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion	Consistent with GALL (see staff evaluation in Section 3.4.2.1)
(7) Carbon steel piping and valve bodies in main steam system	Loss of material due to pitting and crevice corrosion	Water Chemistry	Water Chemistry	Consistent with GALL (see staff evaluation in Section 3.4.2.1)
(8) Closure bolting in high-pressure or high-temperature systems	Loss of material due to general corrosion; crack initiation and growth due to cyclic loading and/or SCC	Bolting Integrity	Systems Monitoring Program	See staff evaluation in Section 3.4.2.4.13.2
(9) Heat exchangers and coolers/condensers serviced by open-cycle cooling water	Loss of material due to general (carbon steel only), pitting, and crevice corrosion, MIC, and biofouling; buildup of deposit due to biofouling	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System	Consistent with GALL (see staff evaluation in Section 3.4.2.1)

(10) Heat exchangers and coolers/condensers serviced by closed-cycle cooling water	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Closed-Cycle Cooling System	Closed-Cycle Cooling Water System	Consistent with GALL (see staff evaluation in Section 3.4.2.1)
(11) External surface of aboveground CST	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Aboveground Carbon Steel Tanks	Not applicable	CST at RNP is fabricated of SS
(12) External surface of buried CST and AFW piping	Loss of material due to general, pitting, and crevice corrosion, and MIC	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	Not applicable	The CST and AFW piping at RNP is not buried
(13) External surface of carbon steel components	Loss of material due to boric acid corrosion	Boric Acid Corrosion	Boric Acid Corrosion	Consistent with GALL (see staff evaluation in Section 3.4.2.1)

3.4.2.1 Aging Management Evaluations in the GALL Report that Are Relied on for License Renewal, Which Do Not Require Further Evaluation

For component groups evaluated in GALL for which the applicant has claimed consistency with GALL, and for which GALL does not recommend further evaluation, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation. The staff also sampled component groups to determine whether the applicant had properly identified those component groups in GALL that were not applicable to its plant.

On the basis of this review, the staff has determined that the applicant's basis for managing aging effects associated with steam and power conversion systems is consistent with GALL.

3.4.2.2 Aging Management Evaluations in the GALL Report That Are Relied On for License Renewal, For Which GALL Recommends Further Evaluation

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL report, and for which the GALL Report recommends further evaluation, the staff reviewed the applicant's evaluation to determine whether it adequately addressed the issues for which the GALL Report recommended further evaluation. In addition, the staff sampled components in these groups during the AMR inspection to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation. The results of the staff's AMR inspection can be found in NRC Inspection Report 50-261/2003-009 (ADAMS Accession Number ML032130040).

The GALL Report indicates that further evaluation should be performed for the aging effects described in the following sections.

3.4.2.2.1 Cumulative Fatigue Damage

Fatigue is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff reviewed the evaluation of this TLAA in Section 4.3 of this SER, following the guidance in Section 4.3 of the SRP-LR.

Table 3.4-1, Item 1, of the LRA identifies components in the main feedwater, steam line, and AFW piping as requiring aging management for cumulative fatigue damage and states that evaluations of these components are consistent with the GALL Report. LRA Table 2.3-37 for the Steam Generator Blowdown System and Table 2.3-31 for the Steam Generator Chemical Addition System also reference Table 3.4-1, Item 1, of the LRA, which states aging management is consistent with the GALL Report. However, the GALL Report does not address cumulative fatigue damage for these systems. The staff issued RAI 3.4.1-3 requesting the applicant to explain the basis for concluding that RNP is consistent with the GALL Report regarding cumulative fatigue damage for the steam generator blowdown system and for the steam generator chemical addition system.

In response by letter dated April 28, 2003, the applicant stated the following.

Since the GALL Report does not address cumulative fatigue for the steam generator blowdown system, this aging effect/mechanism should have been included with LRA Table 3.4-2 for the Steam Generator Blowdown System. LRA Table 3.4-2 provides aging management evaluations that are different from, or not addressed, in the GALL Report. The pressure boundary for the feedwater and AFW systems includes several small sections of chemical addition system piping and isolation valves. These components provide a pressure boundary intended function for the feedwater and AFW systems. Therefore, the several small sections of steam generator chemical addition system are essentially an extension of the feedwater and AFW systems and is referenced in LRA Table 3.4-1, Item 1.

The staff finds the applicant's response reasonable and acceptable because it provides an explanation that the steam generator blowdown system and the steam generator chemical addition system are adequately managed for cumulative fatigue damage.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of cumulative fatigue damage for components in the steam and power conversion systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.4.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

The SRP-LR recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion of carbon steel piping and fittings, valve bodies and bonnets, pump casings, pump suction and discharge lines, tanks, tubesheets, channel heads, and shells (except for main steam system components), and for loss of material due to crevice and pitting corrosion for SS tanks and HX/cooler tubes. The GALL Water Chemistry Program relies on monitoring and control of water chemistry, based on the guidelines in EPRI TR-102134, "PWR Secondary Water Chemistry Guideline—Revision 3," May 1993, for secondary water chemistry in PWRs, to manage the effect of loss of material due to general (carbon steel only), pitting, or crevice corrosion. However, corrosion may occur at locations of stagnant flow conditions. Therefore, the GALL Report recommends that the effectiveness of the Chemistry Control Program should be verified to ensure that corrosion is not occurring.

In addition to the components identified in the GALL Report, RNP LRA credits the Water Chemistry and One-Time Inspection Programs to manage the effect of loss of material due to general (carbon steel only), pitting, or crevice corrosion for flow elements, temperature elements, tubing and fittings, and feedwater heaters fabricated of carbon steel and SS.

The applicant proposed a one-time inspection of select components and susceptible locations to ensure that corrosion is not occurring. The staff reviewed the applicant's proposed program to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation. The staff verified that the applicant's selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. The staff also verified that the proposed inspection would be performed using techniques similar to ASME Code and ASTM standards.

The applicant has proposed the Water Chemistry Program and the One-Time Inspection Program as the AMPs for managing this aging effect. These programs are evaluated in Section 3.0.3 of this SER and are considered appropriate for managing this aging effect.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of loss of material due to general, pitting, and crevice corrosion for components in the steam and power conversion systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.4.2.2.3 Loss of Material Due to General, Pitting, and Crevice Corrosion, Microbiologically Influenced Corrosion, and Biofouling

The SRP-LR recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling for carbon steel piping and fittings for untreated water from the backup water supply in the AFW system.

LRA Table 3.4-1, Item 3, states that RNP does not manage raw water exposure to AFW piping. In the discussion column, RNP states that backup supplies of raw water are available from the SWS and the deepwell pumps, but the backup supplies are not normally aligned. RNP further states that raw water exposure to AFW piping is an extraordinary event and is not considered to be an applicable environment for LR. The staff issued RAI 3.4.1-4 requesting the applicant to explain measures taken to prevent AFW piping exposed to raw water.

In response by letter dated April 28, 2003, the applicant stated the following.

The isolation valves on the service water and the deep well water backup are normally locked closed with the telltale drain valves open to prevent the flow of untreated water to the AFW system. The telltale drain would provide indication of valve leakage and corrective maintenance would be initiated/performed. The AFW system would only be exposed to service water (untreated water) if the CST becomes unavailable during a plant event requiring operation of the AFW system and these contingency measures would be directed by the plant emergency operating procedures.

The staff finds the applicant's response reasonable and acceptable because it provides an explanation of the measures taken by the applicant to prevent AFW piping exposure to raw water sources.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of loss of material due to general, pitting, crevice corrosion, microbiologically influenced corrosion, and biofouling for components in the steam and power conversion systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.4.2.2.4 Loss of Material Due to General Corrosion

The GALL Report recommends further evaluation of programs to manage loss of material due to general corrosion for external surfaces of all carbon steel structures and components, including closure bolting, exposed to operating temperatures less than 212 °F. Such corrosion may be due to air, moisture, or humidity. The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of this aging effect.

See Section 3.4.2.4.13.3 for staff evaluation of certain carbon steel components that are not susceptible to general corrosion.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of loss of material due to general corrosion for components in the steam and power systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.4.2.2.5 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

3.4.2.2.5.1 Summary of Technical Information in the Application

The GALL Report recommends further evaluation of programs to manage the loss of material due to general corrosion (carbon steel only), pitting and crevice corrosion, and MIC, for SS and carbon steel shells, tubes, and tubesheets within the bearing oil coolers (for steam turbine pumps) in the AFW system. Such corrosion may be due to water contamination that affects the quality of the lubricating oil in the bearing oil coolers. The staff reviewed the applicant's proposed program to ensure that an adequate program will be in place for the management of the aging effect.

LRA Table 3.4-1, Item 4, states that the RNP AMR for AFW system pump lubricating oil coolers determined that water contamination of lube oil is not a credible environment because the lube oil system is a closed system. The staff's position is that an environment of lubricating oil contaminated with water may cause loss of material of carbon or SS components due to general corrosion, pitting, crevice corrosion, and MIC. The AFW system pump lubricating oil coolers have the potential of being contaminated with water.

In response to RAI 3.4.1-5, by letter dated June 13, 2003, the applicant stated the following:

> The initial LRA identified service water (raw water) as the cooling medium for the AFW pump lubricating oil coolers. Raw water is the correct environment for the motor-driven pump coolers. However, as noted in the LRA (Table 3.4-2, Item 9), the steam-driven AFW pump is aligned in self-cooling mode. In this mode, the internal environment for the cooler (tube-side) and associated service water piping is treated water (condensate). Therefore, RNP has revised the AMR evaluation to consider the internal environment for the steam-driven pump oil cooler (tube-side) as treated water. This revision to the AMR changed the aging effects identified for the oil cooler, as well as the program(s) assigned to manage the aging effects.
>
> The AFW system pump lubricating oil coolers are closed oil systems. The tube-side environments for these oil coolers are raw water for the motor-driven pumps and treated water for the steam-driven pumps. The shell-side of the subject oil coolers is exposed to a lubricating oil environment. The component intended functions for these heat exchangers include both "heat transfer" and "pressure boundary." Pressure boundary components of these heat exchangers have been evaluated with respect to material and operating environment. The only way for the lube oil side to be contaminated with cooling water is by degradation of the interfacing pressure boundary. Since these HXs have been evaluated for any aging effect that may result in a loss of pressure boundary, the AMR does not need to assume contamination of the lube oil. A review of OE did not identify any history of water intrusion for the subject oil coolers. Additionally, if water enters via a leak, oil/water would run out of the (closed) system and be detected during shift operator rounds. Hence, it is event driven and would be repaired upon discovery.
>
> The oil coolers for the motor-driven AFW pumps have been deemed susceptible to age-related degradation on the raw water side of the heat exchangers (tube-side). As identified in LRA Tables 3.4-1 and 3.4-2, these aging effects include flow blockage due

to fouling, loss of heat transfer effectiveness due to fouling of heat transfer surfaces, and loss of material due to crevice corrosion, galvanic corrosion, pitting, general corrosion, MIC, and selective leaching. These aging effects are co-managed by the Open-Cycle Cooling Water System Program and the Preventive Maintenance Program, as well as the Selective Leaching Program. Assigned PM routing numbers are credited in the Preventive Maintenance Program AMP to manage the identified aging effects. The motor-driven pump oil coolers are cleaned, inspected, and tested on yearly intervals under the RNP Preventive Maintenance Program. The sacrificial anodes are also inspected and replaced, if necessary.

The oil cooler for the steam-driven AFW pump has been deemed susceptible to age-related degradation on the treated water side of the heat exchangers (tube-side). These aging effects include cracking due to SCC, loss of heat transfer effectiveness due to fouling of heat transfer surfaces, and loss of material due to crevice corrosion, galvanic corrosion, pitting, general corrosion, MIC, and selective leaching. These aging effects are co-managed by the Water Chemistry Program and the Preventive Maintenance Program, as well as the Selective Leaching Program. Assigned PM routing numbers are credited in the Preventive Maintenance Program to manage the identified aging effects. The steam-driven pump oil cooler is cleaned, inspected and tested every 18 months under the RNP Preventive Maintenance Program. The sacrificial anode is also inspected and replaced if necessary.

As stated above, the coolers are periodically cleaned, inspected, and tested under the RNP Preventive Maintenance Program. This includes cleaning and inspection of the shell-side (oil), as well as the tube-side. After cleaning and inspection, the coolers are pressure-tested (shell-side). This would identify any degradation of the pressure boundary between the tube-side and the shell-side. After re-assembly, the coolers are refilled with fresh oil and are checked during functional testing. In addition, an oil sample is tested quarterly for the steam-driven AFW pump lube oil cooler and semi-annually for the motor-driven AFW pump oil coolers. A review of laboratory test data dating back to April 1994 support the OE review. No data were reported that would suggest water intrusion.

The applicant's response describes inspections and oil samples used to detect intrusion of water into the oil side of the oil coolers. The staff finds the applicant's response reasonable and acceptable to manage intrusion of water into the oil side of the coolers.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of loss of material due to general, pitting, and crevice corrosion, and MIC for components in the steam and power conversion systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that this aging effect will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.4.2.2.5.2 Staff Evaluation

The GALL Report recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion, and MIC of underground piping and fittings and emergency CST in the AFW system, and the underground condensate storage tank in the condensate system. The Buried Piping and Tanks Inspection Program relies on industry practice, frequency of pipe excavation, and OE to manage the effects of loss of material from general, pitting, and crevice corrosion, and MIC.

In LRA Table 3.4-1, the applicant stated that at RNP, neither the CST nor AFW system piping is buried. Therefore, loss of material due to general, pitting, and crevice corrosion, and MIC of underground piping and fittings and emergency CST in the AFW system, and underground CST in the condensate system is not considered by RNP to be an applicable environment for LR.

During the AMR inspection, the staff reviewed the CST and AFW piping and confirmed that these components are not buried (see NRC Inspection Report 50-261/2003-009; ADAMS Accession Number ML032130040). On the basis of the inspection findings, the staff concludes that the applicant has correctly concluded that CST and AFW piping is not buried and this aging effect is not applicable.

On the basis of its review, the staff finds that neither the CST nor AFW system piping is buried. Therefore, aging management of the loss of material due to general, pitting, and crevice corrosion, and MIC for these components in the steam and power conversion systems, as recommended in the GALL Report, is not required.

3.4.2.2.6 Conclusions

The staff has reviewed the applicant's evaluation of the issues for which GALL recommends further evaluation for components in the steam and power conversion systems in Sections 3.4.2.2.1 through 3.4.2.2.5. On the basis of its review, the staff concludes that the applicant has provided sufficient information to demonstrate that the issues for which GALL recommends further evaluation have been adequately addressed, and that the subject aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3). In addition, the staff concludes that the applicant's UFSAR Supplements provide adequate descriptions of the programs credited with managing these aging effects, as required by 10 CFR 54.21(d).

3.4.2.3 Aging Management Programs for Steam and Power Conversion Systems

In SER Section 3.4.2.1, the staff evaluated the applicant's conformance with the aging management programs recommended by the GALL Report for the steam and power conversion systems. In SER Section 3.4.2.2, the staff reviewed the applicant's evaluation of the issues for which the GALL Report recommends further evaluation. In this SER section, the staff presents its evaluation of the programs used by the applicant to manage the aging of the components in the steam and power conversion systems.

The applicant credits 10 AMPs to manage the aging effects associated with components in the steam and power conversion systems. All 10 of the AMPs are credited with managing aging for components in other system groups (common AMPs). The staff's evaluation of the common AMPs credited with managing aging in steam and power conversion systems components is provided in Section 3.0.3 of this SER. The common AMPs are listed below:

(1) Metal Fatigue of Reactor Coolant Pressure Boundary Program—SER Section 3.0.3.1
(2) Water Chemistry Program—SER Section 3.0.3.3
(3) Boric Acid Corrosion Program—SER Section 3.0.3.4
(4) Flow-Accelerated Corrosion Program—SER Section 3.0.3.5
(5) Open-Cycle Cooling Water System Program—SER Section 3.0.3.7
(6) Closed-Cycle Cooling Water System Program—SER Section 3.0.3.8
(7) One-Time Inspection Program—SER Section 3.0.3.9
(8) Selective Leaching of Material Program—SER Section 3.0.3.10
(9) Systems Monitoring Program—SER Section 3.0.3.11
(10) Preventive Maintenance Program—SER Section 3.0.3.12

On the basis of its review, the staff finds that the applicant has properly identified the applicable aging effects and AMPs for the components in the steam and power conversion systems at RNP, and that the components in the RNP steam and power conversion systems were correctly evaluated in the applicant's AMR and will be adequately managed during the period of extended operation.

There are no plant-specific AMPs for the steam and power conversion systems.

3.4.2.4 Aging Management of Plant-Specific Components

The following sections provide the results of the staff's evaluation of the adequacy of aging management for steam and power conversion systems components.

3.4.2.4.1 Turbine System

3.4.2.4.1.1 Summary of Technical Information in the Application

As described in Section 2.3.4.1, the turbine system converts the thermal energy of the steam from the main steam system into mechanical energy used to drive the main generator and produce the plant's electrical output. Turbine system valves provide overspeed trip of the turbine to prevent generation of turbine blade missiles. The applicant's screening review concluded that the turbine system components do not perform any intended functions for LR; therefore, none of the turbine system components are subject to an AMR.

Staff review of the scoping and screening process in LRA Section 2.3.4.1 concluded that no turbine system components are subject to an AMR.

3.4.2.4.2 Electro-Hydraulic Control System

3.4.2.4.2.1 Summary of Technical Information in the Application

As described in Section 2.3.4.2, the EHC system controls the flow of steam to the turbine system through all phases of turbine operation. The system also provides overspeed trip of the turbine to prevent generation of turbine blade missiles. The applicant's screening review concluded that the turbine system components do not perform any intended functions for LR, therefore, none of the EHC system components are subject to an AMR.

Staff review of the scoping and screening process in LRA Section 2.3.4.2 concluded that no

EHC system components are subject to an AMR.

3.4.2.4.3 Turbine Generator Lube Oil System

3.4.2.4.3.1 Summary of Technical Information in the Application

As described in Section 2.3.4.3, the turbine generator lube oil system provides oil for cooling and lubricating the turbine bearings and turning gear. The system also provides pressurization oil to the turbine system overspeed and protective trip devices. The applicant's screening review concluded that the turbine generator lube oil system components do not perform any intended functions for LR; therefore, none of the turbine generator lube oil system components are subject to an AMR.

Staff review of the scoping and screening process in LRA Section 2.3.4.3 concluded that no turbine generator lube oil system components are subject to an AMR.

3.4.2.4.4 Extraction Steam System

3.4.2.4.4.1 Summary of Technical Information in the Application

As described in Section 2.3.4.4, the extraction steam system provides reheating and moisture removal for the steam flow from the high pressure turbine before it is supplied to the low pressure turbines. The system also provides overspeed protection by providing valves to stop the flow of reheat steam to the low pressure turbine. The applicant's screening review concluded that the extraction steam system components do not perform any intended functions for LR, therefore, none of the extraction steam system components are subject to an AMR.

Staff review of the scoping and screening process in LRA Section 2.3.4.4 concluded that no extraction steam system components are subject to an AMR. However, by letter dated October 23, 2002, the applicant submitted a supplement to the application for renewal of operating license that modified RNP methodology for scoping and treatment of 10 CFR 54.4(a)(2) components described in LRA Section 2.1.1.2. This supplement identified extraction steam system components requiring aging management. SER Section 3.4.2.4.13.4 provides the staff evaluation of these extraction steam system components.

3.4.2.4.5 Main Steam System

3.4.2.4.5.1 Summary of Technical Information in the Application

The AMR results for the main steam system are presented in Tables 3.4-1 and 3.4-2 of the LRA. The applicant used the GALL Report format to present its AMR of main steam system components in LRA Table 3.4-1. In LRA Table 3.4-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP program(s).

As described in Section 2.3.4.5, the main steam system transports saturated steam from the SGs to the main turbine and other secondary steam system components. The system is the principal heat sink for the RCS and protects the RCS and the SGs from overpressurization. The main steam system provides isolation of the SGs following a postulated accident, such as a steam line break, and provides the steam supply to the steam driven AFW pump.

Aging Effects

LRA Tables 3.4-1 and 3.4-2 identify the following applicable aging effects for the main steam system:

- loss of material due to boric acid corrosion of CS components (external surfaces) in air, leaking, and dripping chemically treated borated water environments
- loss of material due to pitting and crevice corrosion of CS components in steam environments
- loss of material due to general corrosion of carbon and low-alloy steel components (external surfaces) in air, moisture, and humidity environments
- wall thinning due to flow-accelerated corrosion of carbon steel components in steam and treated water environments
- cracking from stress-corrosion cracking of SS components in treated water and steam environments
- loss of material due to erosion of carbon steel components in steam and treated water environments
- loss of material due to general, galvanic, pitting, and crevice corrosion of carbon steel components in steam and treated water environments
- loss of material due to crevice and pitting corrosion of SS components in steam and treated water environments

Aging Management Programs

The following AMPs are utilized to manage aging effects to the main steam system:

- Boric Acid Corrosion Program
- Water Chemistry Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program

A description of these AMPs is provided in Appendix B of the LRA.

3.4.2.4.5.2 Staff Evaluation

In addition to Section 3.4 of the LRA, the staff reviewed the pertinent information provided in Section 2.3.4, "Steam and Power Conversion Systems," and the applicable AMP descriptions provided in Appendix B of the LRA to determine whether the aging effects for the main steam system components have been properly identified and will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects and the appropriateness of the programs credited for the aging management of the main steam system components at RNP. The staff's evaluation included a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the appropriateness of the AMPs that are credited for managing the identified aging effects for the main steam system components.

The main steam system flow venturi are within the scope of license renewal but are not specifically identified by RNP as requiring aging management. The staff issued RAI 3.4.1-2 requesting the applicant to explain aging management for these components.

In response by letter dated April 28, 2003, the applicant stated the following.

The main steam flow venturis are constructed of SS (for high wear parts) and carbon steel. For the SS parts, cracking due to thermal fatigue was identified as an applicable aging effect/mechanism. This is addressed in LRA Table 3.4-1, Item 1. These SS parts were also identified as susceptible to loss of material due to Crevice and pitting corrosion and cracking due to SCC and were therefore included in LRA Table 3.4-2, Items 2 and 8. For the carbon steel parts of the main steam flow venturis, loss of material due to aggressive chemical attack and crevice corrosion and pitting corrosion were identified as applicable aging effects/mechanisms. Accordingly, these mechanisms are discussed in LRA Table 3.4-1, Items 7 and 13. In addition, the carbon steel parts of these venturis were found to be susceptible to loss of material due to general and galvanic corrosion. These effect/mechanisms are appropriately addressed in LRA Table 3.4-2, Item 7. Steam is not a liquid and therefore does not act as an electrolyte which is necessary for galvanic corrosion to occur. However, the applicant's methodology conservatively treats steam as treated water with respect to this aging effect. Therefore, as stated above, galvanic corrosion was identified as a potential aging effect for the subject flow venturis.

Based on the applicant's response to RAI 3.4.1-2, the staff concludes that the aging effects of flow venturis are adequately managed.

Component Groups

The component groups identified in LRA Table 2.3.26 for the main steam system are (1) closure bolting, (2) flow orifices and elements, (3) MSIV accumulator tank(s), and (4) valves, piping, tubing, and fittings.

Aging Effects

- loss of material due to boric acid corrosion of carbon steel components (external surfaces) in air, leaking, and dripping chemically treated borated water environments
- loss of material due to pitting and crevice corrosion of carbon steel components in steam environments
- loss of material due to general corrosion of carbon and low-alloy steel components (external surfaces) in air, moisture, and humidity environments

- wall thinning due to flow-accelerated corrosion of carbon steel components in steam and treated water environments

- cracking from stress-corrosion cracking of SS components in treated water and steam environments

- loss of material due to erosion of carbon steel components in steam and treated water environments

- loss of material due to general, galvanic, pitting, and crevice corrosion of CS components in steam and treated water environments

- loss of material due to crevice and pitting corrosion of SS components in steam and treated water environments

Aging Management Programs

The following AMPs are utilized to manage aging effects to the main steam system.

- Boric Acid Corrosion Program
- Water Chemistry Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program

Each of the above AMPs is credited with managing the aging of several components in different structures and systems and is, therefore, considered a common AMP. The staff's review of these common AMPs can be found in Section 3.0.3 of this SER.

After evaluating the applicant's AMR for each of the main steam system components, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in Tables 3.4-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

By letter dated October 23, 2002, the applicant submitted a supplement to the application for renewal of operating license that modified the RNP methodology for scoping and treatment of 10 CFR 54.4(a)(2) components described in LRA Section 2.1.1.2. This supplement identified the main steam system components requiring aging management. SER Section 3.4.2.4.13.4 presents the staff's evaluation of these main steam system components.

The staff has reviewed the information in Sections 2.3.4 and 3.4 of the LRA, as well as the applicable AMP descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the main steam system will be adequately managed so that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4.2.4.6 Steam Generator Blowdown System

3.4.2.4.6.1 Summary of Technical Information in the Application

The AMR results for the SG blowdown system are presented in Tables 3.4-1 and 3.4-2 of the LRA. The applicant used the GALL Report format to present its AMR of SG blowdown system components in LRA Table 3.4-1. In LRA Table 3.4-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s).

As described in Section 2.3.4.6, the SG blowdown system assists in maintaining required SG chemistry by providing a means for removal of foreign matter that concentrates in the steam generators. The system is fed by three independent blowdown lines (one per steam generator) that penetrate containment and tie to a common blowdown drain tank.

Aging Effects

LRA Tables 3.4-1 and 3.4-2 identify the following applicable aging effects for the SG blowdown system.

- loss of material due to boric acid corrosion of carbon steel components (external surfaces) in air, leaking, and dripping chemically treated borated water environments
- cumulative fatigue damage of carbon steel components in steam and treated water environments
- loss of material due to general (carbon steel only), pitting, and crevice corrosion of carbon and SS components in treated water environments
- loss of material due to general corrosion of carbon and low-alloy steel components (external surfaces) in air, moisture, and humidity environments
- wall thinning due to flow-accelerated corrosion of carbon steel components in treated water environments
- loss of material due to galvanic corrosion of carbon steel components in steam and treated water environments
- cracking from stress-corrosion cracking of SS components in a treated water and steam environments
- loss of material due to erosion of carbon steel components in steam and treated water environments

Aging Management Programs

The following AMPs are utilized to manage aging effects to the SG blowdown system.

- Boric Acid Corrosion Program

- Water Chemistry Program
- One-Time Inspection Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program

A description of these AMPs is provided in Appendix B of the LRA.

3.4.2.4.6.2 Staff Evaluation

In addition to Section 3.4 of the LRA, the staff reviewed the pertinent information provided in Section 2.3.4, "Steam and Power Conversion Systems," and the applicable AMP descriptions provided in Appendix B of the LRA to determine whether the aging effects for the SG blowdown system components have been properly identified and will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects and the appropriateness of the programs credited for the aging management of the SG blowdown system components at RNP. The staff's evaluation included a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the appropriateness of the AMPs that are credited for managing the identified aging effects for the SG blowdown system components.

Component Groups

The component groups identified in LRA Table 2.3.27 for the SG blowdown system are (1) closure bolting, (2) flow orifices and elements, and (3) valves, piping, and fittings.

Aging Effects

LRA Tables 3.4-1 and 3.4-2 identify the following applicable aging effects for the steam generator blowdown system:

- loss of material due to boric acid corrosion of carbon steel components (external surfaces) in air, leaking, and dripping chemically treated borated water environments

- cumulative fatigue damage of carbon steel components in steam and treated water environments

- loss of material due to general (carbon steel only), pitting, and crevice corrosion of carbon and SS components in treated water environments

- loss of material due to general corrosion of carbon and low-alloy steel components (external surfaces) in air, moisture, and humidity environments

- wall thinning due to flow-accelerated corrosion of carbon steel components in treated water environments

- loss of material due to galvanic corrosion of carbon steel components in steam and treated water environments

- cracking from stress-corrosion cracking of SS components in a treated water and steam environments

- loss of material due to erosion of carbon steel components in steam and treated water environments

Aging Management Programs

The following Aging Management Programs are utilized to manage aging effects to the steam generator blowdown system:

- Boric Acid Corrosion
- Water Chemistry
- One-Time Inspection
- Systems Monitoring
- Flow-Accelerated Corrosion

Each of the above AMPs previously identified is credited with managing the aging of several components in different structures and systems and is, therefore, considered a common AMP. The staff's review of these common AMPs can be found in Section 3.0.3 of this SER.

After evaluating the applicant's AMR for each of the SG blowdown system components, the staff evaluated the associated AMPs to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in Tables 3.4-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

By letter dated October 23, 2002, the applicant submitted a supplement to the application for renewal of the operating license that modified the RNP methodology for scoping and treatment of 10 CFR 54.4(a)(2) components described in LRA Section 2.1.1.2. This supplement identified the SG blowdown system components requiring aging management. SER Section 3.4.2.4.13.4 presents the staff's evaluation of these SG blowdown system components.

See Section 3.4.2.2.1 for an evaluation of cumulative fatigue damage in SG blowdown system components.

The staff has reviewed the information in Sections 2.3.4 and 3.4 of the LRA, as well as the applicable AMP descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the SG blowdown system will be adequately managed so that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4.2.4.7 Steam Cycle Sampling

3.4.2.4.7.1 Summary of Technical Information in the Application

The AMR results for the steam cycle sampling system are presented in Tables 3.4-1 and 3.4-2 of the LRA. The applicant used the GALL Report format to present its AMR of steam cycle sampling system components in LRA Table 3.4-1. In LRA Table 3.4-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s).

As described in Section 2.3.4.7, the steam cycle sampling system provides for sampling and analysis of SG liquid via sample lines connected to the SG blowdown system. A separate sample line is provided for each SG blowdown line.

Aging Effects

LRA Tables 3.4-1 and 3.4-2 identify the following applicable aging effects for the steam cycle sampling system:

- loss of material due to boric acid corrosion of carbon steel components (external surfaces) in air, leaking, and dripping chemically treated borated water environments
- loss of material due to general (carbon steel only), pitting, and crevice corrosion on the closed-cycle cooling water side of the heat exchanger
- loss of material from general, galvanic, pitting, and crevice corrosion of carbon steel components in a treated water environment

Aging Management Programs

The following AMPs are utilized to manage aging effects to the steam cycle sampling system:

- Water Chemistry
- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Program

A description of these AMPs is provided in Appendix B of the LRA.

3.4.2.4.7.2 Staff Evaluation

In addition to Section 3.4 of the LRA, the staff reviewed the pertinent information provided in Section 2.3.4, "Steam and Power Conversion Systems," and the applicable AMP descriptions provided in Appendix B of the LRA to determine whether the aging effects for the steam cycle sampling system components have been properly identified and will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects and the appropriateness of the programs credited for the aging management of the steam cycle sampling system components at RNP. The staff's evaluation included a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the appropriateness of the AMPs that are credited for managing the identified aging effects for the steam cycle sampling system components.

In Table 2.3.9 of the LRA, the applicant listed the commodity group, "SG Blowdown Heat Exchanger Shell," and links aging management to Table 3.3.1, Item 13, which is the auxiliary system. The staff issued RAI 3.4.1-13 requesting the applicant to explain the basis for referencing Table 3.3-1, Item 13, in the auxiliary system rather than Table 3.4-1, Item 13, in the steam and power conversion systems.

In response by letter dated April 28, 2003, the applicant stated the following.

The steam generator blowdown sample heat exchanger is in the secondary sampling system and has a component intended function only as the system pressure boundary for the CCW system. Therefore, for license renewal purposes, this component is evaluated with the CCW system and the link to Table 3.3.1 is correct.

Based on the applicant's response to RAI 3.4.1-13, the staff concludes that the commodity group, "SG Blowdown Heat Exchanger Shell" aging effects are adequately managed.

<u>Component Groups</u>

The component groups identified in LRA Section 2.3.4.7 for the steam cycle sampling system is heat exchangers.

Aging Effects

LRA Tables 3.4-1 and 3.4-2 identify the following applicable aging effects for the component group of the steam cycle sampling system:

- loss of material due to boric acid corrosion of carbon steel components (external surfaces) in air, leaking, and dripping chemically treated borated water environments
- loss of material due to general (carbon steel only), pitting, and crevice corrosion on the closed-cycle cooling water side of the heat exchanger
- loss of material from general, galvanic, pitting, and crevice corrosion of carbon steel components in a treated water environment

<u>Aging Management Programs</u>

The following Aging Management Programs are utilized to manage aging effects to the component group of the steam cycle sampling system.

- Water Chemistry
- Boric Acid Corrosion Program

- Closed-Cycle Cooling Water System Program

Each of the above AMPs is credited with managing the aging of several components in different structures and systems and is, therefore, considered a common AMP. The staff's review of these common AMPs can be found in Section 3.0.3 of this SER.

After evaluating the applicant's AMR for each of the steam cycle sampling system components, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in Tables 3.4-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

By letter dated October 23, 2002, the applicant submitted a supplement to the application for renewal of the operating license that modified the RNP methodology for scoping and treatment of 10 CFR 54.4(a)(2) components described in LRA Section 2.1.1.2. This supplement identified the steam cycle sampling system components requiring aging management. SER Section 3.4.2.4.13.4 presents the staff's evaluation of these steam cycle sampling system components.

The staff has reviewed the information in Sections 2.3.4 and 3.4 of the LRA, as well as the applicable AMP descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the steam cycle sampling system will be adequately managed so that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4.2.4.8 Feedwater System

3.4.2.4.8.1 Summary of Technical Information in the Application

The AMR results for the feedwater system are presented in Tables 3.4-1 and 3.4-2 of the LRA. The applicant used the GALL Report format to present its AMR of feedwater system components in LRA Table 3.4-1. In LRA Table 3.4-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s).

As described in Section 2.3.4.8, the feedwater system provides preheated, high-pressure feedwater to the steam generators under operating conditions. The system provides for feedwater and blowdown isolation following a postulated loss-of-coolant accident (LOCA) or steam line break event, and assists in maintaining SG water chemistry. The steam generator level is controlled to ensure proper water inventory for various operational and accident conditions. The control is achieved by variations in the feedwater flow rate.

<u>Aging Effects</u>

LRA Tables 3.4-1 and 3.4-2 identify the following applicable aging effects for the feedwater system:

- loss of material due to boric acid corrosion of carbon steel components (external surfaces) in air, leaking, and dripping chemically treated borated water environments
- loss of material due to general (carbon steel only), pitting, and crevice corrosion of carbon and SS components in a treated water environments
- loss of material due to general corrosion of carbon and low-alloy steel components (external surfaces) in air, moisture, and humidity environments
- wall-thinning due to flow-accelerated corrosion of carbon steel components in a treated water environment
- loss of material due to galvanic corrosion of carbon steel components in steam and treated water environments
- cracking from stress-corrosion cracking of SS components in treated water and steam environments
- loss of material due to erosion and flow-accelerated corrosion of carbon steel components in steam and treated water environments

Aging Management Programs

The following AMPs are utilized to manage aging effects to the feedwater system.

- Boric Acid Corrosion Program
- Water Chemistry Program
- One-Time Inspection Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program
- Preventive Maintenance Program

A description of these AMPs is provided in Appendix B of the LRA.

3.4.2.4.8.2 Staff Evaluation

In addition to Section 3.4 of the LRA, the staff reviewed the pertinent information provided in Section 2.3.4, "Steam and Power Conversion Systems," and the applicable AMP descriptions provided in Appendix B of the LRA to determine whether the aging effects for the feedwater system components have been properly identified and will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects and the appropriateness of the programs credited for the aging management of the feedwater system components at RNP. The staff's evaluation included a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the appropriateness of the AMPs that are credited for managing the identified aging effects for the feedwater system components.

Component Groups

The component groups identified in LRA Table 2.3.28 for the feedwater system are (1) closure bolting, (2) feedwater heater heat exchanger cover and tubesheet, (3) feedwater heater heat exchanger cover, (4) feedwater heater heat exchanger tube sheet, (5) feedwater heater heat exchanger tubing, (6) flow orifices and elements, (7) temperature elements, and (8) valves, piping, tubing, and fittings.

Aging Effects

LRA Tables 3.4-1 and 3.4-2 identify the following applicable aging effects for the feedwater system:

- loss of material due to boric acid corrosion of carbon steel components (external surfaces) in air, leaking, and dripping chemically treated borated water environments

- loss of material due to general (carbon steel only), pitting, and crevice corrosion of carbon and SS components in a treated water environments

- loss of material due to general corrosion of carbon and low-alloy steel components (external surfaces) in air, moisture, and humidity environments

- wall thinning due to flow-accelerated corrosion of carbon steel components in a treated water environment

- loss of material due to galvanic corrosion of carbon steel components in steam and treated water environments

- cracking from stress-corrosion cracking of SS components in treated water and steam environments

- loss of material due to erosion and flow-accelerated corrosion of carbon steel components in steam and treated water environments

Aging Management Programs

The following AMPs are utilized to manage aging effects to the feedwater system.

- Boric Acid Corrosion Program
- Water Chemistry Program
- One-Time Inspection Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program
- Preventive Maintenance Program

Each of the above AMPs is credited with managing the aging of several components in different structures and systems and is, therefore, considered a common AMP. The staff's review of these common AMPs can be found in Section 3.0.3 of this SER.

After evaluating the applicant's AMR for each of the feedwater system components, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in Tables 3.4-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

By letter dated October 23, 2002, the applicant submitted a supplement to the application for renewal of the operating license that modified the RNP methodology for scoping and treatment of 10 CFR 54.4(a)(2) components described in LRA Section 2.1.1.2. This supplement identified the feedwater system components requiring aging management. SER Section 3.4.2.4.13.4 for presents the staff's evaluation of these feedwater system components.

Section 3.4.2.2.1 provides the evaluation of cumulative fatigue damage in feedwater system components.

The staff has reviewed the information in Sections 2.3.4 and 3.4 of the LRA, as well as the applicable AMP descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the feedwater system will be adequately managed so that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4.2.4.9 Auxiliary Feedwater System

3.4.2.4.9.1 Summary of Technical Information in the Application

The AMR results for the AFW system are presented in Tables 3.4-1 and 3.4-2 of the LRA. The applicant used the GALL Report format to present its AMR of AFW system components in LRA Table 3.4-1. In LRA Table 3.4-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s).

As described in Section 2.3.4.9, the AFW system supplies feedwater to the steam generators when normal feedwater sources are not available. The system provides for isolation of flow to a faulted steam generator following postulated accidents, such as an SG tube rupture or main steam line break. The AFW system can provide feedwater to any combination of steam generators from any one or combination of three pumps, two of which are motordriven and the third is steamdriven. Steam can be supplied to the steam-driven pump from any of the steam generators. The pumps can take suction from the CST, which is the normal source, or from the SWS or the deepwell pumps if the CST is not available. The steam-driven pump provides an independent and diversely powered means of providing feedwater to the steam generators. The steam-driven subsystem provides the required flow through injection lines that are separate from the motor-driven subsystem.

<u>Aging Effects</u>

LRA Tables 3.4-1and 3.4-2 identify the following applicable aging effects for the AFW system:

- loss of material due to boric acid corrosion of carbon steel components (external surfaces) in air, leaking, and dripping chemically treated borated water environments

- loss of material due to general (carbon steel only), pitting, and crevice corrosion of carbon and SS components in a treated water environment

- wall thinning due to flow-accelerated corrosion of carbon steel components in a treated water environment

- loss of material due to general (carbon steel only), pitting, crevice, and microbiologically influenced corrosion of carbon and SS in raw water environments

- buildup of deposits from biofouling of carbon and SS in a raw water environment

- loss of material due to galvanic corrosion of carbon steel components in steam and treated water environments

- cracking from stress-corrosion cracking of SS components in treated water and steam environments

- loss of material from selective leaching of carbon steel and copper alloy components in raw water environments

- loss of material due to erosion of carbon steel components in steam and treated water environments

- loss of material due to pitting, crevice corrosion, and microbiologically influenced corrosion of copper alloys in raw water environments

- flow blockage from fouling of copper alloys in a raw water environment

- loss of heat transfer effectiveness from fouling of heat transfer surfaces of copper alloys in a raw water environment

- loss of material due to galvanic corrosion of carbon steel components in a raw water environment

<u>Aging Management Programs</u>

The following AMPs are utilized to manage aging effects to the AFW system.

- Boric Acid Corrosion Program
- Water Chemistry Program
- One-Time Inspection Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program
- Open-Cycle Cooling Water System Program
- Selective Leaching of Materials Program

A description of these AMPs is provided in Appendix B of the LRA.

3.4.2.4.9.2 Staff Evaluation

In addition to Section 3.4 of the LRA, the staff reviewed the pertinent information provided in Section 2.3.4, "Steam and Power Conversion Systems," and the applicable AMP descriptions provided in Appendix B of the LRA to determine whether the aging effects for the AFW system components have been properly identified and will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects and the appropriateness of the programs credited for the aging management of the AFW system components at RNP. The staff's evaluation included a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the appropriateness of the AMPs that are credited for managing the identified aging effects for the AFW system components.

Table 3.4-2, Item 10, of the LRA states that the carbon steel steam- and motor-driven AFW pump lube oil heat exchanger waterbox is managed for loss of material from galvanic corrosion in a raw water environment. The staff issued RAI 3.4.1-8 requesting the applicant to explain how the Open-Cycle Cooling Water System Program manages for loss of material from galvanic corrosion in a raw water environment.

In response by letter dated April 28, 2003, the applicant stated the following.

The Open Cycle Cooling Water System Program credits routine inspections for the subject safety-related heat exchangers associated with the Cooling Water Reliability Program (NRC GL 89-13). These inspections are tracked by periodic maintenance activities and managed by the Preventive Maintenance Program.

Based on the applicant's response to RAI 3.4.1-8, the staff concludes that the carbon steel steam- and motor-driven AFW pump lube oil heat exchanger waterbox is adequately managed for loss of material from galvanic corrosion in a raw water environment.

Section 4.3 presents the staff's evaluation of cumulative fatigue damage in AFW system components, Section 3.4.2.2.3 evaluates raw water exposure to AFW piping, and Section 3.4.2.2.5evaluates water contamination in AFW pump lubricating oil coolers.

Component Groups

The component groups identified in LRA Table 2.3.29 for the AFW system are (1) closure bolting, (2) flow orifices and elements, (3) steam-driven auxiliary feedwater (SDAFW) and motor-driven auxiliary feedwater (MDAFW) pump lube oil heat exchanger tubing, (4) SDAFW and MDAFW pump lube oil heat exchanger waterbox, (5) SDAFW and MDAFW pump lube oil heat exchanger tubing and shell, (6) SDAFW and MDAFW pump lube oil heat exchanger shell, (7) SDAFW pump lube oil pump, (8) SDAFW and MDAFW pump, (9) SDAFW turbine, and (10) valves, piping, tubing, and fittings.

Aging Effects

LRA Tables 3.4-1and 3.4-2 identify the following applicable aging effects for the AFW system:

- loss of material due to boric acid corrosion of carbon steel components (external surfaces) in air, leaking, and dripping chemically treated borated water environments
- loss of material due to general (carbon steel only), pitting, and crevice corrosion of carbon and SS components in a treated water environment
- wall thinning due to flow-accelerated corrosion of carbon steel components in a treated water environment
- loss of material due to general (carbon steel only), pitting, crevice, and microbiologically influenced corrosion of carbon and SS in raw water environments
- buildup of deposits from biofouling of carbon and SS in a raw water environment
- loss of material due to galvanic corrosion of carbon steel components in steam and treated water environments
- cracking from stress-corrosion cracking of SS components in treated water and steam environments
- loss of material from selective leaching of carbon steel and copper alloy components in raw water environments
- loss of material due to erosion of carbon steel components in steam and treated water environments
- loss of material due to pitting, crevice corrosion, and microbiologically influenced corrosion of copper alloys in raw water environments
- flow blockage from fouling of copper alloys in a raw water environment
- loss of heat transfer effectiveness from fouling of heat transfer surfaces of copper alloys in a raw water environment
- loss of material due to galvanic corrosion of carbon steel components in a raw water environment

Aging Management Programs

The following AMPs are utilized to manage aging effects to the auxiliary feedwater system.

- Boric Acid Corrosion Program
- Water Chemistry Program
- One-Time Inspection Program
- Systems Monitoring Program

- Flow-Accelerated Corrosion Program
- Open-Cycle Cooling Water System Program
- Selective Leaching of Materials Program

Each of the above AMPs is credited with managing the aging of several components in different structures and systems and is, therefore, considered a common AMP. The staff's review of these common AMPs can be found in Section 3.0.3 of this SER.

After evaluating the applicant's AMR for each of the AFW system components, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in Tables 3.4-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

The staff has reviewed the information in Sections 2.3.4 and 3.4 of the LRA, as well as the applicable AMP descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the AFW system will be adequately managed so that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4.2.4.10 Condensate System

3.4.2.4.10.1 Summary of Technical Information in the Application

The AMR results for the condensate system are presented in Tables 3.4-1 and 3.4-2 of the LRA. The applicant used the GALL Report format to present its AMR of condensate system components in LRA Table 3.4-1. In LRA Table 3.4-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s).

As described in Section 2.3.4.10, the condensate system provides makeup grade water to the steam generators for removing decay and sensible heat from the RCS. The condensate system provides a passive flow of water, by gravity, to the AFW system to support safe shutdown of the plant. The condensate system consists of a CST with piping to the suctions of all three AFW system pumps.

<u>Aging Effects</u>

LRA Tables 3.4-1 and 3.4-2 identify the following applicable aging effects for the condensate system:

- loss of material due to general and galvanic (carbon steel only), pitting, and crevice corrosion of carbon and SS components in a treated water environment

- loss of material due to general corrosion of carbon and low-alloy steel components (external surfaces) in air, moisture, and humidity environments

- wall thinning to due flow-accelerated corrosion of carbon steel components in a treated water environment

- change in material properties and cracking from ultraviolet radiation, ozone exposure, or elevated temperature of elastomers in air and gas environments

- change in material properties and cracking from ultraviolet radiation, ozone exposure, or elevated temperature of elastomers in treated water and steam environments

- loss of material due to erosion of carbon steel components in steam and treated water environments

Aging Management Programs

The following AMPs are utilized to manage aging effects to the condensate system.

- Water Chemistry Program
- One-Time Inspection Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program
- Preventive Maintenance Program

A description of these AMPs is provided in Appendix B of the LRA.

3.4.2.4.10.2 Staff Evaluation

In addition to Section 3.4 of the LRA, the staff reviewed the pertinent information provided in Section 2.3.4, "Steam and Power Conversion Systems," and the applicable AMP descriptions provided in Appendix B of the LRA to determine whether the aging effects for the condensate system components have been properly identified and will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects and the appropriateness of the programs credited for the aging management of the condensate system components at RNP. The staff's evaluation included a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the appropriateness of the AMPs that are credited for managing the identified aging effects for the condensate system components.

Component Groups

The component groups identified in LRA Table 2.3.30 for the condensate system are (1) condensate storage tank, (2) flow orifices and elements, and (3) valves, piping, tubing, and fittings.

Aging Effects

LRA Tables 3.4-1 and 3.4-2 identify the following applicable aging effects for the condensate system.

- loss of material due to general and galvanic (carbon steel only), pitting, and crevice corrosion of carbon and SS components in a treated water environment
- loss of material due to general corrosion of carbon and low-alloy steel components (external surfaces) in air, moisture, and humidity environments
- wall thinning due to flow-accelerated corrosion of carbon steel components in a treated water environment
- change in material properties and cracking from ultraviolet radiation, ozone exposure, or elevated temperature of elastomers in air and gas environments
- change in material properties and cracking from ultraviolet radiation, ozone exposure, or elevated temperature of elastomers in treated water and steam environments
- loss of material due to erosion of carbon steel components in steam and treated water environments

Aging Management Programs

The following AMPs are utilized to manage aging effects to the condensate system.

- Water Chemistry Program
- One-Time Inspection Program
- Systems Monitoring Program
- Flow-Accelerated Corrosion Program
- Preventive Maintenance Program

Each of the above AMPs is credited with managing the aging of several components in different structures and systems and is, therefore, considered a common AMP. The staff's review of these common AMPs can be found in Section 3.0.3 of this SER.

After evaluating the applicant's AMR for each of the condensate system components, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in Tables 3.4-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

By letter dated October 23, 2002, the applicant submitted a supplement to the application for renewal of the operating license that modified the RNP methodology for scoping and treatment of 10 CFR 54.4(a)(2) components described in LRA Section 2.1.1.2. This supplement identified the condensate system components requiring aging management. SER Section 3.4.2.4.13.4 presents the staff's evaluation of these condensate system components.

The staff has reviewed the information in Sections 2.3.4 and 3.4 of the LRA, as well as the applicable AMP descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the condensate system will be adequately managed so that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4.2.4.11 Steam Generator Chemical Addition

3.4.2.4.11.1 Summary of Technical Information in the Application

The AMR results for the steam generator chemical addition system are presented in Tables 3.4-1 and 3.4-2 of the LRA. The applicant used the GALL Report format to present its AMR of SG chemical addition system components in LRA Table 3.4-1. In LRA Table 3.4-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s).

As described in Section 2.3.4.11, the SG chemical addition system provides for chemical addition to the feedwater system for proper SG chemistry control. Portions of the system provide pressure boundary integrity for the feedwater and AFW systems.

Aging Effects

LRA Tables 3.4-1 and 3.4-2 identify the following applicable aging effects for the SG chemical addition system.

- loss of material due to general (carbon steel only), pitting, and crevice corrosion of carbon and SS components in a treated water environment

- loss of material due to general corrosion of carbon and low-alloy steel components (external surfaces) in air, moisture, and humidity environments

- loss of material due to galvanic corrosion of carbon steel components in steam and treated water environments

Aging Management Programs

The following AMPs are utilized to manage aging effects to the SG chemical addition system.

- Water Chemistry Program
- One-Time Inspection Program
- Systems Monitoring Program

A description of these AMPs is provided in Appendix B of the LRA.

3.4.2.4.11.2 Staff Evaluation

In addition to Section 3.4 of the LRA, the staff reviewed the pertinent information provided in Section 2.3.4, "Steam and Power Conversion Systems," and the applicable AMP descriptions provided in Appendix B of the LRA to determine whether the aging effects for the SG chemical addition system components have been properly identified and will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects and the appropriateness of the programs credited for the aging management of the SG chemical addition system components at RNP. The staff's evaluation included a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the appropriateness of the AMPs that are credited for managing the identified aging effects for the SG chemical addition system components.

Component Groups

The component group identified in LRA Table 2.3.31 for the SG chemical addition system is valves, piping, and fittings.

Aging Effects

LRA Tables 3.4-1 and 3.4-2 identify the following applicable aging effects for the SG chemical addition system:

- loss of material due to general (carbon steel only), pitting, and crevice corrosion of carbon and SS components in a treated water environment
- loss of material due to general corrosion of carbon and low-alloy steel components (external surfaces) in air, moisture, and humidity environments
- loss of material due to galvanic corrosion of carbon steel components in steam and treated water environments

Aging Management Programs

The following AMPs are utilized to manage aging effects to the SG chemical addition system.

- Water Chemistry Program
- One-Time Inspection Program
- Systems Monitoring Program

Each of the above AMPs is credited with managing the aging of several components in different structures and systems and is, therefore, considered a common AMP. The staff's review of these common AMPs can be found in Section 3.0.3 of this SER.

After evaluating the applicant's AMR for each of the SG chemical addition system components, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.4-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in Tables 3.4-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

Section 3.4.2.2.1 presents the staff's evaluation of cumulative fatigue damage in SG chemical addition system components.

The staff has reviewed the information in Sections 2.3.4 and 3.4 of the LRA, as well as the applicable AMP descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the SG chemical addition system will be adequately managed so that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4.2.4.12 Circulating Water

3.4.2.4.12.1 Summary of Technical Information in the Application

The AMR results for the circulating water system are presented in Tables 3.3-1 and 3.3-2 of the LRA. The applicant used the GALL Report format to present its AMR of circulating water system components in LRA Table 3.3-1. In LRA Table 3.3-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s).

As described in Section 2.3.4.12, the circulating water system provides cooling water from Lake Robinson to the main condensers to condense the steam discharged from the turbine system. Portions of the system provide a flow path for the SWS flow.

Aging Effects

LRA Tables 3.3-1 and 3.3-2 identify the following applicable aging effect for the circulating water system:

- loss of material due to general galvanic, pitting, and crevice corrosion, microbiologically induced corrosion, and biofouling of carbon and SS, cast iron, bronze, copper, and aluminum in a raw water environment

Aging Management Programs

The following AMP is utilized to manage aging effects to the circulating water system.

- Fire Water Program

A description of this AMP is provided in Appendix B of the LRA.

3.4.2.4.12.2 Technical Evaluation

In addition to Section 3.3 and 3.4 of the LRA, the staff reviewed the pertinent information provided in Section 2.3.4, "Steam and Power Conversion Systems," and the applicable AMP descriptions provided in Appendix B of the LRA to determine whether the aging effects for the circulating water system components have been properly identified and will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects and the appropriateness of the programs credited for the aging management of the circulating water system components at RNP. The staff's evaluation included a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the appropriateness of the AMPs that are credited for managing the identified aging effects for the circulating water system components.

In Table 3.3.2, row 31, of the LRA, the applicant stated that there are no aging effects for circulating water system concrete piping in raw water and buried environments. The staff issued RAI 3.4.1-12 requesting the applicant to explain the methodology for reaching this conclusion. The staff also requested an explanation as to why this line item of the steam and power conversion systems was placed in the auxiliary systems Table 3.3-2 of the LRA rather than in the steam and power conversion systems Table 3.4-2.

In it's response by letter dated June 13, 2003, the applicant stated the following.

The portion of the circulating water system within the scope of license renewal is the discharge line extending from the condenser seal well to the circulating water discharge weir. The 126-inch circulating water discharge water piping was designed to American Water Works Association (AWWA) Standard C301 - reinforced concrete water pipe, steel cylinder type, prestressed. It is routed from the main condenser seal well to the east side of the auxiliary building, and from there to the discharge weir. It is part of the open loop cooling system for the main condenser, and is in operation any time the unit is at power. This non-safety-related piping also provides a discharge flow path for service water heat loads from the auxiliary building to the discharge canal. It runs from approximately 6 feet below grade at the service water connection to about 10 feet below grade at the discharge weir. It was conservatively included in license renewal scope on the basis that it includes the discharge flow path from the safety-related component cooling water heat exchangers to the circulating water system discharge weir. Its only intended function is that it be capable of providing this flow path. The applicant has performed a review to identify aging effects that require aging management for this piping. Since the piping in question is only needed for a service water discharge flow path and is located entirely outside the auxiliary building, the only failure mechanism of concern would be fouling or blockage. While there are many instances of fouling identified in plant and industry operating experience, it is not credible that this 126-inch diameter line could become significantly fouled without being detected on the basis of degraded plant operating conditions. Further, degradation of piping integrity sufficient to impact service water flow is not considered credible based on the following considerations:

- While piping degradation could result in pressure boundary failure and leakage, this would not occlude the piping and therefore not impact the system intended function.

- Based on the relative size of the circulating water piping, a complete structural failure resulting in piping collapse would be necessary to appreciably restrict service water flow. Limited or localized degradation would not result in loss of system intended function.

- Given the relatively shallow placement of the piping, a significant loss of structural integrity would be preceded by pressure boundary failures and detected in the yard area where the piping is routed.

- Because the piping is less than one diameter below grade, it is unlikely that even a complete structural failure would result in total blockage of the flow area.

- Steel reinforced concrete piping is extremely rugged, particularly in buried applications. Operating experience does not support the sudden and complete structural failure of similar piping in like applications.

Based on the applicant's response to RAI 3.4.1-12, the staff concludes that the only intended function of the circulating water discharge water piping is to provide this flow path, that applicable aging effects would not sufficiently degrade piping integrity to impact service water flow. Therefore, the staff concludes that aging management of the 126-inch circulating water discharge water piping is not required.

Component Groups

The component group identified in LRA Table 2.3.32 for the circulating water system is valves, piping, and fittings.

Aging Effects

- loss of material due to general galvanic, pitting, and crevice corrosion, microbiologically induced corrosion, and biofouling of carbon and SS, cast iron, bronze, copper, and aluminum in a raw water environment

Aging Management Programs

The following AMP is utilized to manage aging effects to the circulating water system.

- Fire Water Program

The above AMP is credited with managing the aging of several components in different structures and systems and is, therefore, considered a common AMP. The staff's review of this common AMPs can be found in Section 3.0.3 of this SER.

After evaluating the applicant's AMR for each of the circulating water system components, the staff evaluated the AMPs listed above to determine if it is appropriate for managing the identified aging effects. For those components identified in Table 3.3-1 of the LRA, the staff verified that the applicant credited the AMP(s) recommended by the GALL Report. For the components identified in Tables 3.3-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

The staff has reviewed the information in Sections 2.3.4, 3.3 and 3.4 of the LRA, as well as the applicable AMP descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the circulating water system will be adequately managed so that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4.2.4.12.3 Conclusions

On the basis of its review, the staff concludes that, the applicant has adequately identified the aging effects, and the AMPs credited for managing the aging effects, of the steam and power conversion system plant specific components in Sections 3.4.2.4.1 through 3.4.2.4.12, such that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR Supplement program description and concludes that it provides an adequate program description of the AMPs credited for managing aging of the steam and power conversion system plant specific components, as required by 10 CFR 54.21(d).

3.4.2.4.13 General AMR Issues

3.4.2.4.13.1 Use of the Water Chemistry Program to Manage Galvanic Corrosion

In Table 3.4-2, Item 1, of the LRA, RNP states that the Water Chemistry Program manages galvanic corrosion because it limits electrolytes in the treated water. Because the treated water does contain electrolytes, the staff issued RAI 3.4.1-10 requesting the applicant to explain the basis for concluding that electrolyte levels in the steam and power conversion systems' treated water are below the threshold to produce galvanic corrosion.

In it's response by letter dated April 28, 2003, the applicant stated the following.

Galvanic corrosion is managed through the RNP Water Chemistry Program using the same methods applied for crevice corrosion, general corrosion, pitting corrosion, and stress-corrosion cracking. The RNP Water Chemistry Program requires monitoring and controlling of secondary water chemistry parameters. The parameter limits in effect for steam and power conversion systems are based upon the EPRI "PWR Secondary Water Chemistry Guidelines," TR-102134. This includes controls for pH level and cation conductivity, and includes concentration limits for sodium, fluoride, chloride, sulfate, silica, dissolved oxygen, iron, copper, and hydrazine. In the LRA, these activities were summarized using the term "limiting electrolytes." In total, these controls have been shown by operating experience to have been effective in minimizing each form of electrochemical corrosion, including galvanic corrosion, pitting corrosion, crevice corrosion, general corrosion, and SCC.

3.4.2.4.13.1.1 Staff Evaluation

Based on the applicant's response to RAI 3.4.1-10, the staff concludes that the Water Chemistry Program adequately maintains the chemistry of treated water below the threshold to produce galvanic corrosion, and is therefore an acceptable program to manage galvanic corrosion.

3.4.2.4.13.2 Managing Aging Effects for Bolting

In Table 3.4-1, Item 8, of the LRA, RNP states that the Bolting Integrity Program is not applicable to bolting for the RNP steam and power conversion systems for the management of loss of material due to general corrosion or crack initiation and growth due to cyclic loading and/or SCC. General corrosion of bolting is managed by the Systems Monitoring program. Crack initiation and growth due to cyclic loading for bolting is included in the Section 4.3 system evaluation of fatigue based on plant heatup cycles. Crack initiation and growth due to SCC is not an applicable aging effect because the applicant stated that there are no bolts in the steam and power conversion systems with sufficient specified minimum yield strength (150 ksi) to be susceptible to SCC. Loss of material due to boric acid corrosion for steam and power conversion systems bolting is managed by the Boric Acid Corrosion Program. As discussed in Section 3.3.2.5.2 of this SER, no other aging effects were identified by the applicant.

3.4.2.4.13.2.1 Staff Evaluation

On the basis of the above discussion, the staff considers the aging management of bolting in the steam and power conversion system to be acceptable.

3.4.2.4.13.3 General Corrosion on Exterior Surfaces

In LRA Table 3.4-1, Item 5, the applicant credits the Systems Monitoring Program to manage loss of material due to general corrosion for external surfaces of carbon steel SCs, including closure bolting, exposed to operating temperatures less than 212 °F. The applicant's Systems Monitoring Program is reviewed in Section 3.0.3 of this SER and is considered appropriate for managing this aging effect. However, in LRA Table 3.4-2, Item 11, RNP states that the external surface of carbon steel components would not be susceptible to corrosion if they were located in areas protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack (e.g., borated water leakage). Based on this, the AFW pump and turbine, AFW lube oil heat exchanger and lube oil pump, and the valves, piping, tubing, and fittings of various systems that are located indoors (not-air-conditioned) and are carbon steel are not identified by the LRA to require aging management for loss of material due to external corrosion. The staff issued RAI 3.4.1-11 requesting the applicant to explain the basis for concluding that the external surface of these carbon steel components would not be susceptible to corrosion if they were located in areas protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack.

In it's response by letter, dated April 28, 2003, the applicant stated the following.

The applicant's AMR methodology concluded that external surfaces of carbon steel components would not be susceptible to corrosion if they were located in areas protected from the weather, were not subjected to condensation, and were not subjected to aggressive chemical attack (e.g., borated water leakage). The external surfaces of the carbon steel components that are included in LRA Table 3.4-2, Item 11 were determined to be subjected to an environment meeting the conditions of air-gas, not subjected to condensation or aggressive chemical attack, and protected from weather. If carbon steel components are not exposed to weather, not prone to condensation, and not subject to boric acid leakage, they will experience an insignificant amount of corrosion. Moisture in the form of liquids and alternate wetting and drying is necessary for significant pitting and crevice corrosion in an ambient air environment. The environments under discussion are not exposed to alternate wetting or drying.

3.4.2.4.13.3.1 Staff Evaluation

The staff finds the applicant's response reasonable and acceptable because it provides an explanation that these components are located in an environment that is not susceptible to general corrosion.

3.4.2.4.13.4 Aging Management for 10 CFR 54.4(a)(2) Components

By letter dated October 23, 2002, the applicant submitted a supplement to the application for renewal of the operating license that modified the RNP methodology for scoping and treatment of SCCs described in LRA Section 2.1.1.2. The scoping for 10 CFR 54.4(a)(2) did not include non-safety-related mechanical components, such as piping, tanks, and valves, that are considered Seismic II/I, because the failure of these components during a seismic event is not postulated in the CLB. Based on NRC interim staff guidance, the scope of 10 CFR 54.4(a)(2) is not limited to Seismic II/I supports but includes all non-safety-related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in Section 54.4(a)(1). RNP has modified the scope of license renewal to include the non-safety-related, fluid-containing piping systems that are in plant structures and spaces which contain safety-related SSCs. Steam and power conversion systems containing 10 CFR 54.4(a)(2) components included within the scope of license renewal and requiring aging management included the following:

- extraction steam system
- main steam
- steam generator blowdown
- steam cycle sampling
- feedwater
- condensate
- auxiliary boiler/steam system

The applicant identified the following applicable aging effects for 10 CFR 54.4(a)(2) components in the steam and power conversion systems:

- cumulative fatigue damage of carbon and SS components in steam and treated water environments

- loss of material from crevice corrosion of carbon and SS components in a treated water environment

- loss of material from pitting corrosion of SS components in a treated water environment

- stress-corrosion cracking of SS components in a treated water environment

- loss of material from general corrosion of carbon steel components in a treated water environment

- loss of material from galvanic corrosion of carbon steel components in a treated water environment

- loss of material from erosion and flow-accelerated corrosion of carbon steel components in a treated water environment

- loss of material from general corrosion of carbon steel components in an outdoor environment

- loss of material due to boric acid corrosion of carbon steel components (external surfaces) in air, leaking, and dripping chemically treated borated water environment

The following AMPs are utilized to manage aging effects for 10 CFR 54.4(a)(2) components in the steam and power conversion systems.

- Water Chemistry Program
- Flow Accelerated Corrosion Program
- Systems Monitoring Program
- Boric Acid Corrosion Program

3.4.2.4.13.4.1 Staff Evaluation

On the basis of its review, the staff finds that the aging effects identified for these additional components are consistent with those identified for other steam and power conversion systems components with the same combination of materials and environments included in Section 3.4 of the LRA. In addition, the staff finds that the AMPs credited for managing these aging effects are common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects as identified. The staff's evaluation of the AMPs is documented in Section 3.0.3 of this SER. Therefore, the staff concludes that the applicant has demonstrated that the aging effects associated with these additional non-safety-related steam and power conversion systems components will be appropriately managed during the period of extended operation.

3.4.2.4.13.5 Conclusions

The staff has evaluated the general AMR issues discussed above and concludes that, on the basis of the staff's review of the LRA and the applicant's responses to the staff's RAIs, the applicant has adequately considered (1) water chemistry program to manage galvanic corrosion, (2) bolting, (3) general corrosion of external surfaces, and (4) aging management for the (a)(2) components, in its aging management evaluations, and that the components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable UFSAR Supplement program description and concludes that the UFSAR Supplement provides an adequate description of the AMP credited for managing aging of the above AMR issues to satisfy 10 CFR 54.21(d).

3.4.3 Evaluation Findings

The staff has reviewed the information in Section 3.4 of the LRA. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the steam and power conversion systems, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation. The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited for managing aging effects, as required by 10 CFR 54.21(d).

3.5 Containments, Structures, and Component Supports

This section addresses the aging management of the structures and structural components. The structures that make up this group are described in the following SER sections.

- Containment (2.4.1)
  —Containment Structures (2.4.1.1)
  —Containment Internal Structural Components (2.4.1.2)
  —Containment External Structural Components (2.4.1.3)

- Other Structures (2.4.2)
  —Reactor Auxiliary Building (2.4.2.1)
  —Fuel-Handling Building (2.4.2.2)
  —Turbine Building (2.4.2.3)
  —Dedicated Shutdown Diesel Generator Building (2.4.2.4)
  —Radwaste Building (2.4.2.5)
  —Intake Structures (2.4.2.6)
  —North Service Water Header Enclosure (2.4.2.7)
  —Emergency Operations Facility/Technical Support Center Security Diesel Generator Building (2.4.2.8)
  —Discharge Structures (2.4.2.9)
  —Lake Robinson Dam (2.4.2.10)
  —Pipe Restraint Tower (2.4.2.11)
  —Yard Structures and Foundations (2.4.2.12)
  —Refueling System (2.4.2.13)

As discussed in Section 3.0.1 of this SER, the structures and structural components are included in one of two LRA tables. LRA Table 3.5-1 consists of structural components that are evaluated in the GALL Report, and LRA Table 3.5-2 consists of structural components not addressed in the GALL Report.

3.5.1 Summary of Technical Information in the Application

In LRA Section 3.5, the applicant described its AMR for structural components within the containment, other Class 1 structures, and component supports at RNP. The passive, long-lived components in these structures that are subject to an AMR are identified in LRA Tables 2.4-1 through 2.4-12.

The applicant's AMRs included an evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify aging effects that require management. These reviews concluded that the aging effects requiring management based on RNP operating experience were consistent with aging effects identified in GALL. The applicant's review of industry operating experience included a review of operating experience through 2001. The results of this review concluded that aging effects requiring management based on industry operating experience were consistent with aging effects identified in GALL. The applicant's ongoing review of plant-specific and industry-wide operating experience is conducted in accordance with the RNP's Corrective Action and Operating Experience Programs.

3.5.2 Staff Evaluation

In Section 3.5 of the LRA, the applicant describes its AMR for structural components at RNP. The staff reviewed LRA Section 3.5 to determine whether the applicant had provided sufficient information to demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation, in accordance with the requirements of 10 CFR 54.21(a)(3), for structural components that are determined to be within the scope of license renewal and subject to an AMR.

The applicant referenced the GALL Report in its AMR. The staff has previously evaluated the adequacy of the aging management of structural components for license renewal as documented in the GALL Report. Thus, the staff did not repeat its review of the items described in the GALL Report, except to ensure that the material presented in the LRA was applicable, and to verify that the applicant had identified the appropriate programs as described and evaluated in the GALL Report.

The staff evaluated those aging management issues recommended for further evaluation in the GALL Report, as well as the applicant's AMR for structural components not addressed in the GALL Report. In addition, the staff evaluated the AMPs used by the applicant to manage the aging of structural components. Finally, the staff reviewed the structural components listed in LRA Section 2.4 to determine whether the applicant properly identified the applicable aging effects and AMPs needed to adequately manage the aging effects.

Table 3.5-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.5 that are addressed in GALL.

Table 3.5-1

Staff Evaluation for RNP Structures and Structural Components Described in the GALL Report

Common Components of All Types of PWR and BWR Containment

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Penetration sleeves penetration bellows, and dissimilar metal welds	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA evaluated in accordance with 10 CFR 54.21(c)	TLAA (4.3)	Consistent with GALL. GALL recommends further evaluation (See Section 3.5.2.2.1.6 below).

Penetration sleeves, penetrations bellows, and dissimilar metal welds	Cracking due to cyclic loading, or crack initiation and growth due to SCC	Containment ISI and Containment leak rate test	Containment ISI (B.3.13); Containment leak rate test (B.2.7); Water Chemistry Program (B.2.2) and Boric Acid Corrosion Program (B3.2)	Consistent with GALL. GALL recommends further evaluation (See Section 3.5.2.2.1.7 below).
Penetration sleeves, penetration bellows, and dissimilar metal welds	Loss of material due to corrosion	Containment ISI and containment leak rate test	Containment ISI (B.3.13); Containment leak rate test (B.2.7)	Consistent with GALL. (See Section 3.5.2.1 below).
Personnel airlock and equipment hatch	Loss of material due to corrosion	Containment ISI and containment leak rate test	Containment ISI (B.3.13); Containment leak rate test (B.2.7)	Consistent with GALL. (See Section 3.5.2.1 below).
Personnel airlock and equipment hatch	Loss of leak tightness in closed position due to mechanical wear of locks, hinges, and closure mechanism	Containment leak rate test and plant technical specifications	Containment ISI (B.3.13); Containment leak rate test (B.2.7)	Consistent with GALL. (See Section 3.5.2.1 below).
Seals, gaskets, and moisture barriers	Loss of sealant and leakage through containment due to deterioration of joint seals, gaskets, and moisture barriers	Containment ISI and containment leak rate test	Containment ISI (B.3.13); Containment leak rate test (B.2.7)	Consistent with GALL. (See Section 3.5.2.1 below).

PWR Concrete (Reinforced and Prestressed) and Steel Containment
BWR Concrete (Mark II and III) and Steel (Mark I, II, and III) Containment

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Concrete elements: foundation, walls, dome	Aging of accessible and inaccessible concrete areas due to leaching of calcium hydroxide, aggressive chemical attack, and corrosion of embedded steel	Containment ISI	Containment ISI (B.3.14)	Consistent with GALL. GALL recommends further evaluation (See Section 3.5.2.2.1.1 below).
Concrete elements: foundation	Cracks, distortion, and increases in component stress level due to settlement	Structures Monitoring	Containment ISI (B.3.14)	Consistent with GALL. (See Section 3.5.2.2.2.2 below).
Concrete elements: foundation	Reduction in foundation strength due to erosion of porous concrete subfoundation	Structures Monitoring	None	Consistent with GALL. (See Section 3.5.2.2.1.2. below).
Concrete elements: foundation, dome, and wall	Reduction of strength and modulus due to elevated temperature	Plant-specific	None	Consistent with GALL. GALL recommends further evaluation (See Section3.5.2.2.1 .3 below).
Prestressed containment: tendons and anchorage components	Loss of prestress due to relaxation, shrinkage, creep, and elevated temperature	TLAA evaluated in accordance with 10 CFR 54.21(c)	TLAA (4.5)	Consistent with GALL. GALL recommends further evaluation (See Section 3.5.2.2.1.5 below).

Steel elements: liner plate, containment shell	Loss of material due to corrosion in accessible and inaccessible areas	Containment ISI and Containment leak rate test	Containment ISI (B.3.13); Containment leak rate test (B.2.7)	Consistent with GALL. GALL recommends further evaluation (See Section 3.5.2.2.1.4 below).
Steel elements: vent header, drywell head, torus, downcomers, pool shell	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA evaluated in accordance with 10 CFR 54.21(c)	None	BWR
Steel elements: protected by coating	Loss of material due to corrosion in accessible areas only	Protective coating monitoring and maintenance	None	Not applicable to RNP
Prestressed containment: tendons and anchorage components	Loss of material due to corrosion of prestressing tendons and anchorage components	Containment ISI	None	Not applicable to RNP
Concrete elements: foundation, dome, and wall	Scaling, cracking, and spalling due to freeze-thaw; expansion and cracking due to reaction with aggregate	Containment ISI	Containment ISI (B.3.14)	Consistent with GALL. (See Section 3.5.2.1 below).
Steel elements: vent line bellows, vent headers, downcomers	Cracking due to cyclic loads or crack initiation and growth due to SCC	Containment ISI and Containment leak rate test	None	BWR
Steel elements: Suppression chamber liner	Crack initiation and growth due to SCC	Containment ISI and Containment leak rate test	None	BWR

Steel elements: drywell head and downcomer pipes	Fretting and lock up due to wear	Containment ISI	None	BWR

Class I Structures

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
All Groups except Group 6: accessible interior/exterior concrete & steel components	All types of aging effects	Structures Monitoring	Structures Monitoring Program (B.3.15)	Consistent with GALL. (See Section 3.5.2.2.2.1 below).
Groups 1-3, 5, 7-9: inaccessible concrete components, such as exterior walls below grade and foundation	Aging of inaccessible concrete areas due to aggressive chemical attack and corrosion of embedded steel	Plant-specific	Structures Monitoring Program (B.3.15)	Consistent with GALL. GALL recommends further evaluation (See Section 3.5.2.2.2.2 below).
Group 6: all accessible/inaccessible concrete, steel, and earthen components	All types of aging effects, including loss of material due to abrasion, cavitation, and corrosion	Inspection of water-control structures or FERC/US Army Corps of Engineers dam inspections and maintenance	Dam Inspection Program	Consistent with GALL. (See Section 3.5.2.1 below).
Group 5: liners	Crack initiation and growth from SCC and loss of material due to crevice corrosion	Water Chemistry and monitoring of spent fuel pool water level	Water Chemistry Program and Monitoring of spent fuel pool water level per RNP Technical Specifications	Consistent with GALL. (See Section 3.5.2.1 below).

Group 1-3, 5, 6: all masonry block walls	Crack due to restraint, shrinkage, creep, and aggressive environment	Masonry Wall	Structures Monitoring Program (B.3.15)	Consistent with GALL. (See Section 3.5.2.1 below).
Group 1-3, 5, 7-9: foundation	Cracks, distortion, and increases in component stress level due to settlement	Structures Monitoring	Structures Monitoring Program (B.3.15)	Consistent with GALL. (See Section 3.5.2.2.1.2 below).
Group 1-3, 5-9: foundation	Reduction in foundation strength due to erosion of porous concrete subfoundation	Structures Monitoring	None	Consistent with GALL. (See Section 3.5.2.2.1.2 below).
Group 1-5: concrete	Reduction of strength and modulus due to elevated temperature	Plant-specific	None	Consistent with GALL. GALL recommends further evaluation. (See Sections 3.5.2.2.1.3 and 3.5.2.4.2.2 below.)
Groups 7, 8: liners	Crack initiation and growth due to SCC and loss of material due to crevice corrosion	Plant-specific	None	Not applicable to RNP

Component Supports

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
All Groups: support members: anchor bolts, concrete surrounding anchor bolts, welds, grout pad, bolted connections, etc.	Aging of component support	Structures Monitoring	Structures Monitoring Program (B.3.15)	Consistent with GALL. (See Section 3.5.2.2.3.1 below).
Groups B1.1, B1.2, and B1.3: support members: anchor bolts, welds	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA evaluated in accordance with 10 CFR 54.21(c)	None	Consistent with GALL. GALL recommends further evaluation (See Section 3.5.2.2.3.2 below).
All Groups: support members: anchor bolts, welds	Loss of material due to boric acid corrosion	Boric Acid Corrosion	Boric Acid Corrosion Program (B.3.2)	Consistent with GALL. (See Section 3.5.2.1 below).
Groups B1.1, B1.2, and B1.3: support members: anchor bolts, welds, spring hangers, guides, stops, and vibration isolators	Loss of material due to environmental corrosion and loss of mechanical function due to corrosion, distortion, dirt, overload, etc.	ISI	ASME Section XI, Subsection IWF Program (B.2.6)	Consistent with GALL. (See Section 3.5.2.1 below).
Group B1.1: high strength low-alloy bolts	Crack initiation and growth due to SCC	Bolting Integrity	None	Consistent with GALL. (See Section 3.5.2.1 below).

The staff's review of the structural components for the RNP LRA is contained within four sections of this SER. Section 3.5.2.1 is the staff's review of structures and structural components that the applicant indicated are consistent with GALL and do not require further evaluation. Section 3.5.2.2 is the staff's review of structures and structural components that the applicant indicates are consistent with GALL, and for which GALL recommends further evaluation. Section 3.5.2.3 is the staff evaluation of the AMPs that are specific to the aging management of structural components. Section 3.5.2.4 contains an evaluation of the adequacy of aging management for components in each structure and includes an evaluation of structures and structural components that the applicant indicates are not in GALL.

3.5.2.1 Aging Management Evaluations in the GALL Report That Are Relied On for License Renewal, Which Do Not Require Further Evaluation

For component groups evaluated in the GALL Report for which the applicant has claimed consistency with GALL, and for which GALL does not recommend further evaluation, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation. The staff also sampled component groups to determine whether the applicant had properly identified those component groups in the GALL Report that were not applicable to its plant.

On the basis of this review, the staff has determined that the applicant's basis of managing aging effects associated with structures and structural components is consistent with GALL.

3.5.2.2 Aging Management Evaluations in the GALL Report That Are Relied On for License Renewal, For Which GALL Recommends Further Evaluation

For component groups evaluated in GALL for which the applicant has claimed consistency with GALL, and for which GALL recommends further evaluation, the staff reviewed the applicant's evaluation to determine whether it adequately addressed the issues for which GALL recommended further evaluation. In addition, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation.

The GALL Report indicates that further evaluation should be performed for the component groups described in the following sections.

3.5.2.2.1 Containments

3.5.2.2.1.1 Aging of Inaccessible Concrete Areas

As stated in the SRP-LR, the GALL Report recommends further evaluation to manage the aging effects for containment concrete components located in inaccessible areas, if certain aging mechanisms, including (1) leaching of calcium hydroxide, (2) aggressive chemical attack, or (3) corrosion of embedded steel, are significant. Possible aging effects for containment concrete structural components due to these three aging mechanisms are cracking, change in material properties, and loss of material.

The AMP recommended by the GALL Report for managing the above aging effects for containment concrete components in accessible portions of the containment structures is the ASME Section XI, Subsection IWL (XI.S2) Program. The staff's evaluation of the applicant's ASME Section XI, Subsection IWL Program is found in Section B.3.14 of this SER.

Subsection IWL exempts from examination those portions of the concrete containment that are inaccessible (e.g., foundation, below-grade exterior walls, concrete covered by liner). For inaccessible portions of the containment structure, 10 CFR 50.55a(b)(2)(ix) requires that the licensee evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas.

The applicant addressed the specific criteria defined in the GALL Report regarding the need for further evaluation to manage the potential aging of containment concrete structural components in inaccessible areas in LRA Table 3.5-1. The GALL Report recommends further evaluation for containment concrete in inaccessible areas if certain aging mechanisms, including (1) leaching of calcium hydroxide, (2) aggressive chemical attack, or (3) corrosion of embedded steel are significant.

Regarding the aging mechanism, leaching of calcium hydroxide, the applicant stated the following in LRA Table 3.5-1.

> RNP concrete is not exposed to flowing water, is dense, well cured, has low permeability, and was constructed in accordance with ACI recommendations at the time of construction. Thus, leaching of calcium hydroxide is not applicable to RNP concrete structures.

Regarding the aging mechanisms, aggressive chemical attack and corrosion of embedded steel, the applicant stated the following in LRA Table 3.5-1.

> RNP ground water values for chlorides and sulfates are much less than the threshold values necessary for aggressive chemical attack. However, the aging mechanisms associated with aggressive chemical attack and corrosion of embedded steel are potentially applicable to below-grade concrete structures owing to slightly acidic ground water (average pH of 4.4). The ASME Section XI, Subsection IWL Program is applicable to the containment structure. However, RNP will enhance the inspection requirements to apply a special inspection provision for monitoring aging effects potentially caused by aggressive chemical attack and corrosion of embedded steel.

Since the below-grade reinforced concrete at RNP is exposed to an aggressive environment (low pH), the staff requested, in RAI 3.5.1-3, that the applicant provide available RNP ground water chemistry test results including chlorides, sulphate, and pH values, and discuss the proposed AMP, as well as past inspection results of below-grade concrete at RNP. RAI 3.5.1-9 stated that the staff is unclear as to how the inspection for below-grade containment concrete will be performed by the ASME Section XI, Subsection IWL Program and requested that additional information, such as the locations, depth, and frequency of soil excavation, related to the AMR of below-grade containment concrete be provided. In response to RAI 3.5.1-3, the applicant stated the following.

Based on a long-term environmental monitoring report, from 1975 to 1995, the following environmental parameters have been identified for lake water at the intake structure:

average chloride concentration 3.14 ppm
average sulfate concentration 3.67 ppm
average pH 5.46

Based on semi-annual ground water monitoring reports, required by the State of South Carolina, the following environmental parameters have been identified from Well #4.

chloride concentration no data available
sulfate concentration 21.0 ppm
ground water pH 4.41

In response to RAI 3.5.1-9, the applicant stated the following.

> Based on the relatively low pH value for both ground water and lake water, an aggressive environment was assumed for the determination of aging effects associated with below-grade concrete.

The intended scope for the inspection of below-grade concrete, related to Item 7 of LRA Table 3.5-1, includes the concrete foundation and below-grade walls for the containment structure. The referenced AMP for this item is the Containment ISI Program for IWL, which is implemented through two plant procedures, the IWL inspection procedure and the site excavation backfill procedure. The inspection of inaccessible, below-grade concrete will be performed using the inspection criteria of ASME Section XI, Subsection IWL, for the subject item.

The site excavation procedure requires the user to notify design engineering of proposed excavations and requires an inspection prior to backfilling against exposed concrete surfaces. Excavations will not be performed with the sole purpose of concrete inspection. However, below-grade examinations of concrete have been performed at certain locations with satisfactory results. These include a below-grade section of the RAB, internal surfaces of electrical manholes exposed to ground water, submerged portions of the intake structure, and the dam spillway exposed to lake water. The lake water environment for the intake structure and dam spillway is essentially the same as that of aggressive ground water (pH values are both below 5.5, and chloride and sulfate levels are well below the trigger levels). As such, inspection results of the submerged portions should envelop aging effects encountered by below-grade concrete of other structures.

Having reviewed the applicant's response above, as well as its response to RAI B.3.14-1, the staff requested the applicant to provide a summary of the results of inspections performed in the below-grade sections of the RAB, the submerged portions of the intake structure, and the dam spillway that would support a conclusion that the below-grade structures have not been degraded, and the scope of the enhanced inspection is adequate to detect any significant degradation of the below-grade structures during the extended period of operation. The applicant provided the following response.

A summary of the results of inspections performed in the (1) below-grade sections of the RAB, (2) submerged portions of the intake structure, (3) dam spillway, and (4) other below-grade concrete are provided below:

(1) below-grade sections of the RAB

A visual inspection of the below-grade portion of the RAB foundation approximately three feet deep was performed in July 1999 while the east foundation was exposed during excavation for construction of the north service water header support slab. This general visual inspection monitored for spalling, scaling, erosion, swelling, bulging, signs of corrosion, cracking, settlement, and exposed rebar. In addition, the interior of manholes 35 and 36, which about the

RAB, were inspected on September 30, 2002. The interior, which had been exposed to ground water since initial construction, had no signs of spalling or other concrete degradation.

(2) submerged portion of the Intake Structure

An inspection of the inaccessible areas was performed during RFO-19 from September 28, 1999, to October 2, 1999, using divers and video equipment. The results of the inspection are as follows. The concrete surface had very little marine growth. There was little or no sediment on the bottom slab. The concrete located at the water line showed signs of erosion from the constant wave action. The top coat of mortar has eroded away leaving the aggregate exposed. The average loss of cover is approximately 1/16 inch to 1/8 inch. The concrete surface was cleaned of marine growth in a number of locations with a wire brush. The top coat came off with minor effort, thereby exposing the aggregate. Sound material was observed at all cleaned locations. Several repairs were observed to have been made in various locations. One repair had flaked off and rebar was observed (one end cut). The repair material thickness was approximately 2 inches and the repair area was about 1 square foot. This area was determined by the RNP Engineering Section to have no impact on the structural integrity of the concrete.

(3) dam spillway

An underwater inspection was performed on June 20, 2000, by divers. The spillway inspection examined the condition of concrete, especially at the tainter gates. A spalled portion of concrete (6" by 8" by 4" deep) was identified. This area is scheduled to be reinspected and repaired prior to the period of extended operation. The Dam Inspection Program will monitor the condition of the normally inaccessible submerged spillway concrete surfaces at a frequency not to exceed 10 years. No other underwater concrete degradation was identified.

(4) other

The interiors of eight security manholes were visually examined in August 2002. The interior concrete has been partially submerged from ground water and provides a similar environment as below-grade concrete (exposure to slightly acidic ground water). No cracking, loss of material, or change in material properties was observed in the concrete surface.

In a conference call with the applicant which occurred on June 16, 2003, the staff pointed out that the applicant did not specify appropriate remedial measures to be followed if the results of RNP's periodic, submerged inspection of the intake structure concrete show significant concrete degradation. Subsequent to this conference call, the applicant, through an email communication, has agreed to the following in order to ensure adequate aging management of below-grade structural concrete that is within the scope of the AMR:

- Degradation to submerged concrete observed during periodic under water inspections at the intake structure and RNP dam spillway will be used as a leading indicator for potential degradation to below-grade concrete structures in the scope of license renewal. Below-grade concrete will be evaluated and/or examined for potential degradation and corrective actions taken as determined by Engineering. This applies to below-grade concrete examined by the Structures Monitoring Program (SMP) and the ASME Section XI, Subsection IWL Program. Applicable SMP and IWL Program procedures will be enhanced to incorporate these changes.

- Ground water and lake water monitoring results (pH, chlorides, sulfates) will be reviewed by Engineering and trended. Increasing aggressiveness of the ground water and lake water will also be used as a leading indicator for potential degradation to below-grade concrete structures in the scope of license renewal as described above.

- Below-grade concrete, when exposed during excavation, already requires notification of Engineering for inspection. However, degradation to below-grade concrete due to aggressive ground water, when exposed during excavation, will also be used as a leading indicator for potential degradation to other below-grade concrete structures in the scope of license renewal as described above.

The staff finds the above commitments adequate to address its concerns regarding the aging management of below-grade, in-scope concrete structural components at RNP. The applicant also committed to provide appropriate documentation of the above agreement. This item was designated as Confirmatory Item 3.5-1.

By letter dated August 14, 2003 (RNP Serial RNP-RA/03-0094), the applicant responded to a number of Confirmatory Items identified by the staff (via an email dated July 14, 2003, from Mr. S.K. Mitra, NRC, to Mr. Roger Stewart, RNP). The staff reviewed the revised contents of Items 25, 26, and 27 of Attachment II (Revised License Renewal Commitments) to the applicant's August 14, 2003, letter. The staff also reviewed the specific response to Confirmatory Item 3.5-1 provided in Attachment III (Response to License Renewal Confirmatory Items) to the same letter. Based on these reviews, the staff finds that the applicant has provided adequate information Confirmatory Item 3.5-1 is closed.

Because of the slightly acidic RNP ground water environment, the applicant conservatively assumed existence of an aggressive chemical environment and proposed the above described plant-specific AMPs (an enhanced ASME Section XI, Subsection IWL Program for containment and an enhanced Structures Monitoring Program for other Category 1 structures) to manage the aging effects of below-grade concrete. As such, the staff finds RAIs 3.5.1-3 and 3.5.1-9 to be fully resolved.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of aging of inaccessible concrete areas for containment, as recommended in the GALL Report.

3.5.2.2.1.2 Cracking, Distortion, and Increase in Component Stress Level Due to Settlement; Reduction of Foundation Strength due to Erosion of Porous Concrete Subfoundations, If Not Covered by Structures Monitoring Program

As stated in the SRP-LR, the GALL Report recommends, for the containment foundation, further evaluation of certain aging effects, including (1) cracking due to settlement, and (2) change in material properties as manifested by a reduction of foundation strength due to erosion of the porous concrete subfoundation, if these two effects are not covered by a structures monitoring AMP. In addition, the GALL Report recommends verification of the continued functionality of a dewatering system during the license renewal period, if relied on by the applicant to lower the site ground water level.

The applicant addressed the above criteria defined in the GALL Report regarding the need for further evaluation to manage the potential aging of the containment foundation in LRA Table 3.5-1. In row entries 8 and 9 of LRA Table 3.5-1, the applicant stated that the aging effect were not applicable. However, based on the applicant's response to Interim Staff Guidance on Concrete Aging (letter to NRC Serial: RNP-RA/02-0159), the applicant stated RNP would examine accessible concrete using the SMP or the IWL Program. For the containment structure, the applicant is using the IWL Program for managing the aging effects of cracking, change in material properties, and loss of material. The staff's evaluation of the applicant's IWL Program is found in Section B.3.14 of this SER.

Regarding the aging effect, cracking due to settlement, the applicant stated the following in row 8 of the LRA Table 3.5-1.

The RNP AMR determined that cracking due to settlement is not applicable. Monitoring for settlement was performed during construction of the plant. Based on the results of the monitoring program and 30 years of operating experience, settlement is not an applicable aging mechanism and no dewatering system was used at RNP. Refer to Table 3.5-1 of this SER.

Regarding the reduction in strength due to erosion of porous concrete subfoundation, the applicant stated the following in row 9 of the LRA Table 3.5-1.

The RNP AMR for concrete determined that RNP concrete foundations are not constructed of porous concrete and, therefore, are not susceptible to this aging mechanism. Refer to Table 3.5-1 of this SER. Table 3.5-1 lists "none" for the AMP for this effect because porous concrete does not exist at RNP.

Because the applicant is managing cracking and change in material properties for the containment foundation as recommended by the GALL Report, the staff finds that the applicant has adequately addressed this further evaluation criteria.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of cracking, distortion, and increase in component stress level due to settlement and the reduction of foundation strength due to erosion of porous concrete subfoundations for containment components, as recommended in the GALL Report.

3.5.2.2.1.3 Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature

As stated in the SRP-LR, the GALL Report recommends, for the containment structure, further evaluation to manage the aging effect change in material properties as manifested by a reduction in strength and modulus, if any portion of the containment concrete exceeds the temperature limit of 150 °F. The GALL Report notes that the implementation of Subsection IWL examinations and 10 CFR 50.55a would not be able to detect the reduction of concrete strength and modulus due to elevated temperature and also notes that no mandated aging management exists for managing this aging effect.

The GALL Report recommends that a plant-specific evaluation be performed if any portion of the concrete containment components exceeds specified temperature limits, (i.e., general temperature 66 °C (150 °F) and local area temperature 93 °C (200 °F)). The staff verified that the applicant's discussion in the renewal application indicated that the affected PWR containment components are not exposed to temperatures that exceed the above temperature limits. For concrete containment components that operate above these temperature limits, the staff reviewed the applicant's proposed programs to ensure that the effects of elevated temperature will be managed during the period of extended operation.

The applicant addressed the above criterion defined in the GALL Report regarding the need for further evaluation in LRA Table 3.5-1. In row 10 of LRA Table 3.5-1, the applicant stated the following regarding temperatures within the containment structure.

Generally, RNP concrete elements do not experience temperatures that exceed the temperature limits associated with aging degradation due to elevated temperature. During an accident, uninsulated concrete may experience a temperature greater than 200 °F for less than 10 seconds, but this was considered to have minimal effects. Therefore, this aging effect is not applicable. However, a TLAA was evaluated to demonstrate the continuing capability of one containment penetration when subject to temperature cycles that exceed 200 °F in adjacent concrete.

RNP subsequently determined the concrete temperature surrounding the subject containment penetration did not exceed 200 °F. The TLAA for this was therefore eliminated. The applicant asserted that RNP concrete elements do not experience temperatures that exceed the temperature limits associated with aging degradation due to elevated temperature. Therefore, this aging effect is not applicable.

In RAI 3.5.1-12, the staff requested that the applicant provide further information regarding the highest temperatures of in-scope concrete elements at RNP, with respect to general high temperature areas and localized hot spots, and compare them to the ACI 349 Code temperature limits. In response to RAI 3.5.1-12, the applicant stated the following.

No concrete elements at RNP exceed the ACI 349 Code temperature limits. The maximum ambient atmospheric air temperatures are as follows for the various RNP in-scope structures:

Outdoor 95 °F
Indoor Air Conditioned 85 °F
Indoor Not Air Conditioned 104 °F (excluding containment)
Containment 120 °F (bulk average temperature)

Based on initial conditions used in the design basis analyses, the containment bulk average temperature is maintained below 120°F and verified through Technical Specifications surveillance on a 24 hour frequency. As such, containment bulk average temperature is below the ACI normal operation value for general areas (i.e., 150 °F).

The temperature of concrete in the vicinity of the reactor vessel is kept within acceptable limits by the reactor vessel insulation casing, air spacing between the insulation and primary shield wall, and supplemental cooling. Concrete in this area is managed by the Structures Monitoring Program and no degradation has been identified.

Localized hot spots within containment can be characterized as the pressurizer cubicle and the concrete surrounding hot piping penetrations. Documented temperatures for the pressurizer cubicle are as follows:

175 °F (9 percent of the time)
165 °F (25 percent of the time)
155 °F (66 percent of the time)

These values are below the ACI 349 normal operation value for local areas (200 °F).

There are no concrete areas around containment penetrations where sustained temperatures exceed 200 °F.

Based on the RNP operational data reported above, the staff determined that (1) the monitoring and management of the concrete temperature for the RNP containment concrete is based on periodic temperature measurements at key containment locations, some of which are verified through Technical Specifications surveillance on a 24 hour frequency, (2) containment bulk average temperature is below the ACI normal operation value for general areas (i.e., 150 °F), and (3) there are no localized concrete hot spots within containment or around containment penetrations where sustained temperatures exceed the 200 °F acceptance limit set by ACI 349 Code. These RNP specific operational data provide an acceptable basis for the staff to conclude that the applicant has implemented reasonable and adequate procedures for managing elevated temperature induced containment concrete degradation. As such, the applicant's response to RAI 3.5.1-12 is acceptable.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of the reduction of strength and modulus of concrete structures due to elevated temperatures for structures and structural components, as recommended in the GALL Report.

3.5.2.2.1.4 Loss of Material Due to Corrosion in Inaccessible Areas of Steel Containment Shell or Liner Plate

As stated in the SRP-LR, the GALL Report recommends further evaluation to manage the aging effect, loss of material due to corrosion for the embedded containment liner, if corrosion of the embedded liner is significant. The AMP recommended by the GALL Report for managing loss of material for accessible steel elements within the containment structure is the ASME Section XI, Subsection IWE (XI.S1) Program. The staff's evaluation of the applicant's ASME Section XI, Subsection IWE Program is found in Section 3.0.3.3 of this SER.

Subsection IWE exempts from examination portions of the containments that are inaccessible, such as embedded or inaccessible portions of steel liners and steel containment shells, piping, and valves penetrating or attaching to the containment. To cover inaccessible areas, 10 CFR 50.55a(b)(2)(ix) requires that the licensee evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas.

The applicant addressed the above criterion defined in the GALL Report regarding the need for further evaluation to manage the potential aging of the embedded containment liner in LRA Table 3.5-1. In row entry 12 of LRA Table 3.5-1, the applicant stated the following regarding the potential for significant corrosion of the RNP steel containment liner.

Certain inaccessible areas in the Containment were identified which are required to be evaluated because conditions exist in accessible areas that could indicate the presence of or result in degradation to inaccessible areas. These areas include the containment liner plate at elevation 228 feet and the containment liner plate beneath the concrete floor below 228 feet. As noted in the 90-day ISI Summary Report submitted by letter RNP-RA/ 01- 0125, dated 8/10/2001, these areas have been evaluated to be acceptable until 2005. A One-Time Inspection Program action has been identified to verify the results of the evaluation and to manage any aging effects at these locations. At that time, the GALL-recommended AMPs will continue to manage the aging effects. This is consistent with the GALL Report. In addition, if the corrosion is caused by leakage of borated water onto carbon steel components, the Boric Acid Corrosion Program in addition to the ISI Program would be applied to manage the localized degradation caused by aggressive chemical attack.

Therefore, the ASME Section XI, Subsection IWE, the 10 CFR 50, Appendix J, the Boric Acid Corrosion, and One-Time Inspection Programs are used to manage corrosion in accessible and inaccessible areas. Aging management for this component/commodity group is consistent with the GALL Report.

In RAI 3.5.1-7, the staff raised a concern regarding the potential for loss of material associated with inaccessible containment vessel liners located below the concrete and requested the applicant to explain how the portions of inaccessible containment vessel liners that are located below the concrete were evaluated. The staff also requested that the applicant briefly summarize the basis for concluding that the other "inaccessible" areas below the concrete are acceptable for continued service until 2005. The applicant stated the following in its response to RAI 3.5.1-7.

A section of the liner was examined (approximately 1 foot deep by 4 feet long in a pre-existing void) below the concrete floor at the 228 foot elevation. A visual examination determined there were tightly adhered corrosion products on the liner surface. A UT examination for actual liner plate thickness determined there was no loss of material thickness. Water samples located in this void area were alkaline, stagnant, low re-oxygenation, low chloride concentration, and low boron concentration. The vertical liner below the concrete floor was in better condition and less pitted than the liner surface immediately above the concrete floor. The liner surface immediately above the concrete floor had pitting corrosion up to 0.1875 inch which was the worst case. This corrosion rate was estimated based on the worst-case degradation occurring from the containment flooding event in 1975 to the liner inspections in 1998 (0.1875 inch/ 23 years). The corrosion rate was then applied to the difference between the actual thickness examined for the liner and minimum design thickness. The worst-case corrosion area above the concrete was determined to conservatively meet the liner design thickness until year 2005. The liner plate thickness below the concrete, which had no degradation, was determined to be acceptable (exceeding the minimum wall thickness) for continued service until 2005. By 2005, either further evaluation or inspection will be required for the inaccessible portion of the liner below the concrete.

In RAI 3.5.1-19, the staff requested that the applicant provide a basis for concluding that (1) the existing conditions of the containment liner (behind the moisture barrier) and the moisture barrier are acceptable, and (2) the inspection to be performed under a One-Time Inspection Program will be sufficient to monitor the condition of the containment liner behind the insulation and the moisture barrier during the extended period of operation. In response to RAI 3.5.1-19, the applicant provided the following response.

The existing condition of the containment liner (behind the moisture barrier) and the moisture barrier was determined to be acceptable based on visual examinations. These visual examinations of the containment liner, behind the removed moisture barrier, determined that the corrosion observed did not impact the structural integrity or leak tightness of the containment.

The inspection to be performed under the One-Time Inspection Program was determined to be sufficient to monitor the condition of the containment liner behind the insulation and the moisture barrier during the extended period of operation. Liner plate areas (behind the moisture barrier) with identified corrosion will be prepared, re-coated, and a new moisture barrier installed. No additional examinations are planned beyond those required by the IWE Program. In accordance with LRA Table 3.5-1, Items 6 and 12, the existing IWE Program is committed to for the extended period of operation, and the one-time inspection will be completed before the end of 2005.

Because the existing condition of the containment liner (behind the moisture barrier) and the moisture barrier itself was determined to be acceptable based on visual examinations, and because the applicant has committed to perform a One-Time Inspection Program to reconfirm the acceptability of the condition of the containment liner behind the insulation, the staff finds that the applicant has provided a reasonable basis for concluding that the aging of the containment liner behind the insulation and the moisture barrier will be adequately managed consistent with its CLB during the extended period of operation. In addition, the ASME XI, Subsection IWE Program manages the aging of the accessible portions of the liner with the stipulation that the applicant evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. As such, the staff considers that RAIs 3.5.1-7 and 3.5.1-19 are closed.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of the loss of material due to corrosion in inaccessible areas of the steel containment shell or liner plate for structures and structural components, as recommended in the GALL Report. Due to the corrosion of the liner plate, the applicant proposed to implement a one-time inspection and to take necessary remedial actions that might be required as a result of the one-time inspection to ensure the integrity of the containment liner during the extended period of operation, thus, adequately fulfilling the further evaluation provision recommended by the GALL Report.

3.5.2.2.1.5 Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature

As stated in the SRP-LR, the GALL Report identifies loss of prestress due to relaxation, shrinkage, creep, and elevated temperature for prestressed containment tendons and anchorage components as a TLAA to be performed for the period of extended operation. The applicant covered this TLAA in Section 4.5 of the application and the staff evaluation of this TLAA is addressed in Section 4.5 of this SER.

Because the prestressing tendons of RNP containment are protected from corrosion by means of specially formulated grout, the requirements of Subsection IWL are not applicable to the

RNP prestressing tendons.

In addition to loss of prestress, the staff also evaluated loss of material as a potential aging effect for the containment tendons and anchorage components. LRA Section 3.5 states that the tendons and their anchorage components are embedded and cannot be accessed for inspection. In addition, the applicant had performed inspections of sample surveillance blocks at 5-year and 25-year intervals. Based on the results of the inspection of these surveillance blocks, the applicant concluded that grouting has proven to be an effective means of preventing corrosion of the tendons and anchorage components.

To get an understanding of the surveillance block tendons and their role in preventing corrosion of the containment tendons, the staff issued RAI 3.5.1-20. Following is the applicant's response.

a) The surveillance tendons consist of six 1-3/8 inch diameter bars grouted in a six inch pipe sheath with anchor plates and prestressing hardware, which is identical to the service tendon except for the length. They are embedded in a section of concrete approximating the same environment as that of the service tendons. The surveillance blocks were placed next to the containment to subject them to a similar unsheltered outdoor environment.

b) The surveillance tendons are 1-3/8 inches in diameter which is the same size as the tendons used in the containment structure.

c) There are no records that would indicate the surveillance block tendons were prestressed. However, inspection results from the surveillance note a snap-back of the tendons into the casing as each rod was severed. The test lab suggested that the snap-back indicated a level of stress had been maintained in the rods by the grout.

d) The surveillance blocks were not instrumented for time-dependent stress/strain measurements.

e) The conclusions for both the 5- and 25-year surveillance blocks indicate there is no significant corrosion, and mechanical testing of the tendon bars also show no significant change in properties. While no specific inspection criteria were provided for the grout, it was noted that the grout cracked as the pipe was cut and stress relieved from the bars. Also in some areas, separated grout had a reddish-brown stain at the contact surface with the bars that was suspected to be an oxide that formed during construction.

The applicant also provided the detailed reports with photographs to the staff.

As indicated at the beginning of this section, the applicant addressed the loss of prestress due to relaxation, shrinkage, creep, and elevated temperature aging effects as part of RNP's TLAA in Section 4.5 of the LRA. The staff evaluation of this TLAA, including the above RNP response to RAI 3.5.1-20, is presented in Section 4.5 of this SER.

Having reviewed the information provided in Section 4.5 and Appendix A of the LRA and the applicant's responses to RAIs 3.5.1-20, 4.5-1, 4.5-2, and 4.5-3, including a commitment to perform structural integrity testing (SIT) and making the necessary observations during the tests, the staff finds the applicant's RAI responses and its commitment to perform SIT reasonable and acceptable because it would assess the integrity of the prestressing tendons and the RNP containment during the extended period of operation. RAI 3.5.1-20 is considered closed and closure of RAIs 4.5-1 through 4.5-3 is provided in Section 4.5 of this SER. On the basis of the above findings, the staff concludes that there is reasonable assurance that the structures and structural components subject to loss of prestress aging effects will be adequately managed during the period of extended operation.

3.5.2.2.1.6 Cumulative Fatigue Damage

As stated in the SRP-LR, the GALL Report identifies cumulative fatigue damage as a TLAA for penetration sleeves, penetration bellows, and dissimilar metal welds to be performed for the period of extended operation. The applicant covered this TLAA in Section 4.6of the application, and the staff evaluation of this TLAA is addressed in Section 4.6 of this SER.

On the basis of the staff's review of LRA Section 4.3.5 , the staff concludes that the containment penetration bellows subject to fatigue will be adequately managed during the period of extended operation.

3.5.2.2.1.7 Cracking Due to Cyclic Loading and SCC

As stated in the SRP-LR, the GALL Report recommends further evaluation of the AMPs to manage cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading or SCC for all types of PWR containments. Containment ISI and leak rate testing may not be sufficient to detect cracks. The staff evaluated the applicant's proposed programs to verify that adequate inspection methods will be implemented to ensure that cracking of containment penetrations is detected.

Items 2 and 3 of Table 3.5-1 of the LRA discuss the plant-specific operating experience related to cracking due to SCC and/or cyclic loading, as well as loss of material of the penetration sleeves and bellows. In addition to its Containment Inservice Inspection and Containment Leak Rate Testing AMPs, the applicant uses its Water Chemistry Program to identify degradation of SS components which are subjected to borated, treated water. The applicant uses its Boric Acid Corrosion Program if the corrosion is caused by leakage of borated water on carbon steel components. To better understand the plant-specific operating experience related to the degradation of penetration bellows, the staff requested additional information in RAIs 3.5.1-16 and 3.5.1-17.

RAI 3.5.1-16 requested the applicant to provide further information regarding the leak rate testing of the containment bellows. In response to RAI 3.5.1-16, the applicant provided the following information.

(a) Bellows (inside and outside containment) are testable by Appendix J, Type B testing.

(b) Administrative leakage limits are not established for individual penetrations that have bellows. However, administrative limits are established for groups of mechanical penetrations. If any group of mechanical penetrations exceeds its administrative limit, individual penetration(s) can be isolated for evaluation and repair. This allows detection of degradation of individual bellows on the penetrations during Type B testing. The overall leakage limit is specified in the Technical Specifications section 5.5.16.

(c) Type B tests are conducted on a refueling outage interval, not to exceed a maximum interval of two years. This frequency of testing will continue to be used for the extended period of operation. In addition, the following information is provided:

A review of plant OE determined many of the original bellows have been replaced. Replacements were generally made due to excessive leakage from damaged bellows. The following OE provides assurance the 10 CFR 50 Appendix J Program has been successful at detection of leakage at penetration bellows and implementing actions to replace bellows as necessary. Before 1992, several bellows were replaced with like-for-like bellows when leakage was identified. This was determined by monitoring the PPS which was used at that time to continuously provide design pressure to the containment penetrations. This system is now only used for testing. No aging mechanisms were determined for these replacement bellows. On July 20, 1995, a potential breach of containment integrity was discovered when the PPS indicated leakage greater than the limits established in the Technical Specifications. A Steam Generator Blowdown (SGB) bellows failed due to a crack caused by TGSCC. Condensation of water from the PPS supplied air inside the penetration wetted the pipe insulation and transported the chlorides contained in the insulation materials to the penetration bellows. The presence of the chlorides on the SS material of the bellows caused the bellows to fail. Additional thermal stresses due to isolation of service water to the penetration coolers contributed to the event. The penetration bellows and end plates were removed on all the SGB bellows per a plant modification. The insulation was replaced with chloride free insulation. Pipe caps replaced the inside end plates. Based on a new design without bellows, the aging mechanism no longer exists for the SGB line penetrations. This was also documented in a Licensee Event Report (LER 95-005-00). On October 7, 1996, a leak was found on the bellows inside the containment on penetration 63, sleeve 5. This was discovered during pressure testing of a new bellows installed on penetration 51, which is also on sleeve 5. It was found that the bellows convolutions had been compressed and damaged due to work performed on other bellows in the area during a previous outage. The penetration bellows were replaced in Refueling Outage-18. There were no aging mechanisms identified.

RAI 3.5.1-17 requested that the applicant provide further information regarding the accessibility of the outside plate/bellows and the possible existence of a penetration pressurization system (PPS) at RNP, which continuously monitors the leakage from the penetrations. The applicant provided the following response to RAI 3.5.1-17.

(a) Outside plate/bellows are accessible for inspection. However, these plates/bellows are not part of the containment pressure boundary and are only used during testing.

(b) The penetration pressurization system (PPS) installed at RNP does not continuously monitor the leakage from the penetrations. The PPS is used during power operation to test the personnel airlock and during outages to test containment penetrations (local leak rate tests). The PPS was originally installed as a continuous monitoring system but the system was modified in 1995 to change to an intermittent monitoring system, and PPS was isolated to the containment penetrations.

Based on the fact that (1) the Type B leak rate testing, performed as part of the 10 CFR Part 50, Appendix J testing, has been successful at detecting leakage at penetration bellows, (2) the applicant has replaced degraded bellows as necessary, and (3) the appropriate AMPs, as discussed above, are credited to manage the aging of the identified components, the staff finds that the applicant has adequately evaluated the management of cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading and SCC, as recommended in the GALL Report. On the basis of this finding, the staff concludes that there is reasonable assurance that this aging effect will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3). As such, RAIs 3.5.1-16 and 3.5.1-17 are considered closed.

3.5.2.2.1.8 Conclusions

The staff has reviewed the applicant's evaluation of the issues for which GALL recommends further evaluation for the containment structural components in Sections 3.5.2.2.1.1 through 3.5.2.2.1.7. On the basis of its review, the staff finds that the applicant has provided sufficient information to demonstrate that the issues for which GALL recommends further evaluation have been adequately addressed and that the subject aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the UFSAR Supplements for the AMPs and concludes that they provide adequate summary descriptions of the programs and activities credited for managing the effects of aging for containment components for which the applicant claimed consistency with GALL to satisfy 10 CFR 54.21(d).

3.5.2.2.2 Class I Structures

3.5.2.2.2.1 Aging of Structures Not Covered by Structures Monitoring Program

As stated in the SRP-LR, the GALL Report recommends further evaluation for certain structure/aging effect combinations, if they are not covered by the applicant's Structures Monitoring Program. These include (1) scaling, cracking, and spalling due to repeated freeze-thaw for Groups 1-3, 5, and 7-9 structures, (2) scaling, cracking, spalling, and increase in porosity and permeability due to leaching of calcium hydroxide and aggressive chemical attack for Groups 1-5 and 7-9 structures, (3) expansion and cracking due to reaction with aggregates for Groups 1-5 and 7-9 structures, (4) cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel for Groups 1-5 and 7-9 structures, (5) cracks, distortion, and increase in component stress level due to settlement for Groups 1-3, 5, and 7-9 structures, (6) reduction of foundation strength due to erosion of porous concrete subfoundation for Groups 1-3 and 5-9 structures, (7) loss of material due to corrosion of structural steel components for Groups 1-5, 7, and 8 structures, (8) loss of strength and modulus of concrete structures due to elevated temperatures for Groups 1-5 structures, and (9) crack initiation and growth due to SCC and loss of material due to crevice corrosion of SS liner for Groups 7 and 8 structures. Further evaluation is necessary only for structure/aging effect combinations that are not covered by the applicant's Structures Monitoring Program.

The applicant addressed the above criterion defined in the GALL Report regarding the need for further evaluation to manage the potential aging of concrete and steel structural components, in LRA Table 3.5-1. In row entry 16 of LRA Table 3.5-1, the applicant stated the following.

The Structures Monitoring Program is applied to components/commodities in this group that have aging effects. For concrete, the RNP AMR methodology concluded that above-grade concrete/grout structures have no aging effects; for steel, in addition to the Structures

Monitoring Program, the Boric Acid Corrosion Program is applicable for corrosion caused by leakage of borated water onto carbon steel components of this component/commodity group; protective coatings are not credited for aging management of steel components; Lubrite Reactor Pressure Vessel Supports use bearing plates of high strength, hard tool steel instead of Lubrite and owing to the wear-resistant material used, the low frequency of movement, and the slow movement between sliding surfaces, mechanical wear was determined not to be an aging mechanism, and similarly, lock-up due to wear is not considered to be an aging effect at RNP.

The above statements by the applicant raised a question as to whether the applicant will use its Structures Monitoring Program to manage the aging effects identified above, as recommended in the GALL Report. The staff issued RAI 3.5.1-8 to clarify this concern. In response to RAI 3.5.1-8, the applicant stated the following.

The letter from J. Moyer (CP&L) to NRC, Serial: RNP-RA/02-0159: "Supplement to Application for Renewal of Operating License," dated October 23, 2002, addresses aging management of concrete components. RNP committed to an AMP for monitoring accessible concrete based on Interim Staff Guidance, and agreed to credit the Structures Monitoring Program and the Dam Inspection Program for examination of accessible concrete. The Component/Commodity Group of "Reinforced Concrete" or "Concrete Tank Foundation" includes grout. Masonry block walls were not specifically identified in the October 23, 2002, letter. However, the Structures Monitoring Program is credited for monitoring the masonry block walls. LRA Table 3.5.1, Item 16, should state that based on Interim Staff Guidance, the Structures Monitoring Program will be used to monitor accessible concrete. LRA Table 3.5-2, Item 10, should be deleted. LRA Table 3.5.1, Item 20, should state that based on Interim Staff Guidance, the Structures Monitoring Program will be used to monitor accessible masonry walls. Based on GALL XI.S5, the Structures Monitoring Program can be used for the aging management of masonry walls.

The above response resolved the staff's concern regarding the concrete components listed in Item 16 of the LRA Table 3.5-1; however, the applicant did not commit to use the Structures Monitoring Program to manage the aging effects of the carbon steel components listed in Item 16. On May 22, 2003, the staff had a telephone conference to inform the applicant that full resolution of the RAI requires the aging management for all of the steel components listed in Item 16 of LRA Table 3.5-1. The applicant proposed to append with the following sentence.

In addition, the Structures Monitoring Program will be used for aging management of the steel components listed in LRA Table 3.5.1, Item 16.

Because the applicant is managing the aging effects for both the concrete and steel structural items covered by Item 16 of LRA Table 3.5-1, as recommended by the GALL Report, the staff finds that the applicant has adequately addressed this further evaluation criterion and RAI 3.5.1-8 is considered closed. The staff's evaluation of the applicant's Structures Monitoring Program is found in Section 3.5.2.3.5 of this SER.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of aging of structures not covered by the Structures Monitoring Program, as recommended in the GALL Report.

3.5.2.2.2.2 Aging Management of Inaccessible Areas

As stated in the SRP-LR, the GALL Report recommends further evaluation for aging of inaccessible concrete areas, such as below-grade foundation and exterior walls exposed to ground water, due to aggressive chemical attack, if an aggressive below-grade environment exists. An aggressive below-grade environment could result in either cracking or loss of material for concrete components subjected to such an environment. The GALL Report recommends that a plant-specific AMP be developed by the applicant, if an aggressive below-grade environment exists.

The applicant addressed the above criterion defined in the GALL Report, regarding the potential aging of below-grade concrete exposed to an aggressive environment, in LRA Table 3.5-1. In item 17 of LRA Table 3.5-1, the applicant stated the following.

The aging mechanisms associated with aggressive chemical attack and corrosion of embedded steel are applicable only to below-grade concrete/grout structures owing to the slightly acidic pH of ground water. The Structures Monitoring Program is applicable to these structures. RNP will apply a special, plant-specific inspection provision to monitor aging effects caused by aggressive chemical attack and corrosion of embedded steel for below-grade concrete in this component/commodity group. This will include inspection of below-grade concrete and grout that is exposed during excavation. These aging management activities are consistent with the GALL Report.

In RAI 3.5.1-10, the staff asked the applicant to explain how the inspection for below-grade Class I structural concrete will be performed by an RNP plant-specific AMP, as recommended in the GALL Report. The staff also requested the applicant to provide additional information, such as the locations, depth, and frequency of soil excavation. The applicant provided the following response to RAI 3.5.1-10.

Inspection of inaccessible, below-grade concrete will be performed using the concrete inspection criteria of the Structures Monitoring Program for the subject item., e.g., planned construction, corrective maintenance, etc. Inaccessible, below-grade, concrete will be inspected when it is exposed during plant excavations for other activities. The site excavation procedure requires notification of Engineering for proposed excavations, and requires an inspection prior to backfilling. Such below-grade examinations of concrete have been performed at certain locations with satisfactory results. These include a below-grade section of the RAB, internal surfaces of electrical manholes exposed to ground water, submerged portions of the intake structure, and the dam spillway exposed to lake water. The lake water environment for the intake structure and dam spillway is essentially the same as that of aggressive ground water (pH values are both below 5.5, and chloride and sulfate levels are well below the trigger levels). Therefore, inspection results of the submerged portions should envelope aging effects encountered by below-grade concrete of other structures. For additional information regarding inspection of inaccessible, below-grade, concrete associated with the containment pressure boundary, please refer to the RNP Response to RAI 3.5.1-3.

As stated previously in Section 3.5.2.2.1.1 of this SER, the staff found that RNP's approach of inspecting below-grade concrete only when it happens to be exposed during plant excavations done for other activities to be insufficient. As such, the staff requested further measures be taken to ensure the adequate aging management of below-grade concrete at RNP. In response to the staff's concerns, the applicant proposed to use its periodic inspections of the submerged portions of the intake structure and dam spillway as indicators for the condition of below-grade concrete at RNP. Because the ground water and lake chemistry are similar, degradation to submerged concrete will be used as a leading indicator for the potential degradation to below-grade concrete structures. This commitment was designated as Confirmatory Item 3.5-1.

Based on the discussion related to closure of Confirmatory Item 3.5-1 provided in Section 3.5.2.2, "Aging Management Evaluations in the GALL Report That Are Relied On for License Renewal, For Which GALL Recommends Further Evaluation," of this SER, Confirmatory Item 3.5-1 is closed.

The staff finds that the applicant has adequately evaluated the aging management of inaccessible concrete areas for Category 1 structures, as recommended in the GALL Report.

3.5.2.2.2.3 Conclusions

The staff has reviewed the applicant's evaluation of the issues for which GALL recommends further evaluation for Class I structures in sections 3.5.2.2.2.1 and 3.5.2.2.2.2. On the basis of its review, the staff finds that the applicant has provided sufficient information to demonstrate that the issues for which GALL recommends further evaluation have been adequately addressed and that the subject aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the UFSAR Supplement for the AMPs and concludes that they provide adequate summary descriptions of the programs and activities credited for managing the effects of aging for Class I structures for which the applicant claimed consistency with GALL to satisfy 10 CFR 54.21(d).

3.5.2.2.3 Component Supports

3.5.2.2.3.1 Aging of Supports Not Covered by Structures Monitoring Program

As stated in the SRP-LR, the GALL Report recommends further evaluation of certain component support/aging effect combinations if they are not covered by the Structures Monitoring Program. This includes (1) reduction in concrete anchor capacity due to degradation of the surrounding concrete for Groups B1-B5 supports, (2) loss of material due to environmental corrosion for Groups B2-B5 supports, and (3) reduction/loss of isolation function due to degradation of vibration isolation elements, for Group B4 supports. Further evaluation is necessary only for the structure/aging effect combinations listed above that are not covered by the applicant's Structures Monitoring Program.

The applicant addressed the above criterion defined in the GALL Report, regarding the need for further evaluation to manage the potential aging of component supports, in LRA Table 3.5-1. In item 25 of LRA Table 3.5-1, the applicant stated that it will use its Structures Monitoring Program to manage the aging effects identified in the preceding paragraph. The applicant further stated that RNP's Structures Monitoring Program will be enhanced to assure that additional concrete structures, which provide support to component support members, are included in the required monitoring. Carbon steel parts of slide bearing plates used for non-ASME components are also included in this Item 25 group.

Since the applicant is managing the aging effects for the component supports covered by Item 25 of LRA Table 3.5-1, as recommended by the GALL Report, the staff finds that the applicant has adequately addressed this further evaluation criterion. The staff's evaluation of the applicant's Structures Monitoring Program is found in Section 3.5.2.3.5 of this SER.

3.5.2.2.3.2 Cumulative Fatigue Damage Due to Cyclic Loading

As stated in the SRP-LR, the GALL Report identifies cumulative fatigue damage as a TLAA for support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports, if a CLB fatigue analysis exists. Since a CLB fatigue analysis does not exist at RNP, cumulative fatigue damage for component supports is not addressed by the applicant.

3.5.2.2.3.3 Conclusions

The staff has reviewed the applicant's evaluation of the issues for which GALL recommends further evaluation for component supports. On the basis of its review, the staff finds that the applicant has provided sufficient information to demonstrate that the issues for which the GALL recommends further evaluation have been adequately addressed and that the subject aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the UFSAR Supplement for the AMP and concludes that it provides an adequate summary description of the programs and activities credited for managing the effects of aging for component supports for which the applicant claimed consistency with GALL to satisfy 10 CFR 54.21(d).

3.5.2.3 Aging Management Programs for Containment, Structures, and Component Supports

In SER Section 3.5.2.1, the staff evaluated the applicant's conformance with the aging management recommended by GALL for containment, other Class I structures, and component support component groupings. In SER Section 3.5.2.2, the staff reviewed the applicant's evaluation of the issues for which GALL recommends further evaluation. In this SER section, the staff presents its evaluation of the programs used by the applicant to manage the aging of the component groups within the containment, other Class I structures, and component supports.

RNP credits 13 AMPs to manage the aging effects associated with the containment, other Class 1 structures, and components supports. Four of the AMPs are credited to manage aging for components in other system groups (common AMPs), six AMPs are credited with managing aging only for structural components, and three are evaluated as mechanical systems. The staff's evaluation of the common AMPs credited with managing in structures is provided in Section 3.0.3. The AMPs evaluated as machanical systems include:

- Fire Water System Program (SER Section 3.3.2.3.3)
- Fire Protection Program (SER Section 3.3.2.3.2)
- Inspection of Overhead Heavy-Load and Light-Load Handling Systems Program (SER Section 3.3.2.3.1)

The common AMPs include the following programs:

- Water Chemistry Program (SER Section 3.0.3.3)
- Boric Acid Corrossion Program (SER Section 3.0.3.4)
- One-Time Inspection Program (SER Section 3.0.3.9)
- Preventive Maintenance Program (SER Section 3.0.3.12)

The staff's evaluation of the six structure-specific AMPs are provided in the sections below.

3.5.2.3.1 ASME Section XI, Subsection IWE Program

3.5.2.3.1.1 Summary of Technical Information in the Application

The applicant described its ASME Section XI, Subsection IWE Program in Section B.3.13 of the LRA. The LRA states that this program is consistent with GALL Program XI.S1, "ASME Section XI, Subsection IWE," with the following exceptions, (1) RNP will use the One-Time Inspection Program for inspecting inaccessible portions of the containment liner and the moisture barrier inside the containment at the liner plate/floor concrete interface, (2) RNP identified additional aging mechanisms not identified in the GALL Report (e.g., aggressive chemical attack for the containment liner plate and galvanic and general corrosion for penetration bellows), and (3) RNP did not identify SCC for the penetration sleeve and bellows because the environmental stressors required to initiate cracking from SCC are not present at RNP.

The applicant credits the ASME Section XI, Subsection IWE Program for aging management of selected components of the reactor containment building at RNP. The applicant identified the following aging effects/mechanisms of concern, (1) loss of material due to general corrosion, (2) loss of material due to galvanic corrosion, (3) loss of material due to aggressive chemical attack, (3) loss of material due to crevice corrosion, (4) loss of material due to pitting corrosion, (5) change in material properties due to elevated temperature, (6) cracking due to elevated temperature, and (7) cracking due to thermal fatigue.

The applicant further stated that, as a result of the license renewal review, administrative controls associated with program element *Confirmation Process* for the program will be enhanced to (1) specify the requirements for conducting reexaminations, and (2) document that repairs meet the specified acceptance standards.

Under the program element "Operating Experience," the applicant states that the program is implemented and maintained in accordance with the general requirements of engineering programs, and asserts that the programs (in general) are effectively implemented through the use of qualified personnel and adequate resources, and are managed in accordance with plant administrative controls. Moreover, the applicant makes a point that generic operating experience includes NUREG-1522, "Assessment of Inservice Conditions of Safety Related Nuclear Plant," June 1995, and that RNP was one of the six plants that was inspected in support of this document.

In the plant-specific operating experience, the applicant identifies degradation of containment as (1) corrosion of the cylinder wall at the bottom of the equipment hatch, (2) degradation of protective insulation sheathing, (3) cracking due to transgranular stress-corrosion cracking

(TGSCC) of a SG blowdown penetration bellows, (4) localized bulging of the containment liner, (5) numerous instances of corrosion of liner, and (5) potential for boric acid leakage penetrating the epoxy construction seal in the vicinity of the emergency core cooling system (ECCS) sump. For these occurrences, the applicant states that it has taken appropriate corrective actions. The applicant further states that this AMP is continually upgraded based on the industry experience and research, and that the Corrective Action Program has been effective in ensuring that the program is continually improving.

3.5.2.3.1.2 Staff Evaluation

In LRA Section B.3.13, "ASME Section XI, Subsection IWE Program," the applicant described its program to manage aging of the containment building at RNP. The LRA states that this program is consistent with GALL Program XI.S1, "ASME Section XI, Subsection IWE," with the following exceptions, (1) RNP will use the One-Time Inspection Program for inspecting inaccessible portions of the containment liner and the moisture barrier inside the containment at the liner plate/floor concrete interface, (2) RNP identified additional aging mechanisms not identified in the GALL Report (e.g., aggressive chemical attack for the containment liner plate and galvanic and general corrosion for penetration bellows), and (3) RNP did not identify SCC for the penetration sleeve and bellows because the environmental stressors required to initiate cracking from SCC are not present at RNP. The staff confirmed the applicant's claim of consistency during the AMR inspection. Furthermore, the staff reviewed the deviations and their justification to determine whether the AMP, with the deviations, remains adequate to manage the aging effects for which it is credited. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program. In addition, the staff determined whether the applicant properly applied the GALL program to its facility.

The staff conceptually considers the Appendix J Program as a program to ensure the leak-tight integrity of the containment (as described in GALL Section XI.4), and the Containment Inservice Inspection Program (Subsection IWE program) as the AMP for detecting the aging degradation of containment pressure boundary components. These programs complement each other and are required to assure that the containment continues to perform its intended functions as described in Table 2.4-1 of the LRA. The LRA appropriately describes the purpose of the program; however, the staff requested clarification of some of the program elements and exceptions (GALL Section XI.S1) associated with the ASME XI Section, Subsection IWE Program.

In addressing the program element *Confirmation Process*, the applicant stated that the program will be enhanced to require reexaminations and document that repairs meet the specified acceptance standards. The requirements for supplemental examinations, additional examinations, and documentation of acceptance criteria are parts of Subsection IWE of the ASME Code, as modified by 10 CFR 50.55a, and endorsed in GALL Section XI.S1. The staff asked the applicant, in RAI B.3.13-1, to provide information regarding what the enhancements consist of which are not currently required. By letter dated April 28, 2003, the applicant provided the following response.

> The site procedure for the IWE Program meets the requirements of IWA-4000, IWA-2200, and Table IWE-3410-1 for repairs and reexaminations, except as allowed by 10 CFR 50.55a(b)(2)(ix)(B) and approved requests for relief. However,

> an improvement was recommended to add the following statement to the IWE Program procedure: "Reexaminations are conducted in accordance with the requirements of IWA-2200, and the recorded results are to demonstrate that the repair meets the acceptance standards set forth in Table IWE-3410-1." This was recommended to clearly summarize the requirements in one location.

The staff considers the applicant's action of incorporating all the acceptance criteria in one location prudent in implementing the requirements of Subsection IWE of Section XI of the ASME Code and finds it acceptable.

Based on the database on degradation of the moisture barrier between the concrete floor and the cylinder liner, Subsection IWE of Section XI of the ASME Code (as referenced in GALL Section XI.S1) requires 100 percent examination of the moisture barrier once every inspection interval. During the IWE examinations, a number of licensees have discovered degradation of moisture barriers and significant corrosion of liner plates below the concrete floor levels. The staff asked the applicant, in RAI B.3.13-2, to provide a technical justification for the exception taken (i.e., one-time inspection of this area). By letter dated April 28, 2003, the applicant provided the following response.

> RNP has received NRC approval for relief from Subsection IWE of ASME Section XI. This is documented in a letter from Herbert N. Berkow (NRC) to D.E. Young (CP&L) dated July 26, 1999 titled, "Evaluation of Relief Requests IWE/IWL-1 through IWE/IWL-9: Implementation of Subsections IWE and IWL of ASME Section XI For Containment Inspection for Carolina Power and Light Company's H. B. Robinson Steam Electric Plant, Unit No. 2 (HBRSEP2) (TAC No. MA4637)." Relief Request IWE/IWL-01 has been approved to provide a VT-3 examination on those portions of the insulated moisture barriers and liner plate that are exposed when a maintenance activity requires removal of the insulation. Although Relief Requests IWE/IWL-01 and IWE/IWL-02 do not require examination of these "inaccessible" areas, 10 CFR 50.55a(b)(2)(ix)(a) does require the evaluation of these inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. These areas of the moisture barrier and containment liner were made accessible by removing the liner insulation and performing an examination. These areas were analyzed as stated in RNP Response to RAI 3.5.1-19 and determined not to impact the structural integrity or leak-tightness of containment. Some areas of the moisture barrier and liner plate are behind permanent structures, or due to ALARA concerns some could not be inspected. These inaccessible areas were analyzed and determined not to impact the structural integrity or leak-tightness of containment and determined to be acceptable for continued service until 2005, based on using worst case corrosion rates as discussed in the RNP Responses to RAI 3.5.1-7 and RAI 3.5.1-19. A one-time inspection was assigned for completing these inspections by year 2005. If additional inspections are required, they will be determined and scheduled at that time.

The staff reviewed this response in conjunction with the applicable relief request and the responses provided to RAIs 3.5.1-7 and 3.5.1-19. Based on these reviews, the staff determined that (1) by the 2005 outage, the applicant will perform a focused inspection of the liner plate behind the moisture barrier and the insulation at the junction of the wall and the concrete at elevation 228 ft., (2) the applicant will perform the periodic examination of these areas as required by 10 CFR 50.55a and Subsection IWE, and (3) as a result of the inspection performed in 2005, if additional inspections are required, the applicant will determine the time and schedule of the additional examinations. Based on this determination, the staff finds the mechanism used by the applicant to monitor these areas acceptable.

The applicant summarized its implementation process, and the operating experience related to the degradation of the liner, protective insulation sheathing, penetration bellows, bulging of the liner plate, and corrosion of the external vertical liner plate of the ECCS sump. The applicant stated that it has evaluated all these degradations, taken corrective actions where warranted, and ensured itself that the requirements of containment structure are met. The staff asked the applicant, in RAI B.3.13-3, to provide acceptance criteria for bulging of the liner plate. By letter dated April 28, 2003, the applicant provided the following response.

> The bulge in the containment liner was analyzed in the "HB Robinson Unit No. 2 Containment Liner Stress Analysis Report," dated June 21, 1974. A finite element approach was used for the liner and stud stress analysis. Broken adjacent stud anchors were postulated. Neither the stud load nor liner stress exceeded the allowable criteria of the materials used. The bulged liner and remaining anchor studs were determined to be effective to meet their functional requirements during a LOCA and during normal plant operating conditions. The bulge is believed to have been present since initial construction. A strain monitoring program was initiated for one cycle which indicated no gross movement or growth of the liner. A letter from E. Utley (CP&L) to Robert W. Reid (NRC), Serial NG-76-443, dated March 25, 1976, summarized the findings and provided a summary of the analysis used to demonstrate the integrity of the bulged liner. Two additional bulged liner areas were discovered in 1992. These areas are also believed to have existed since initial construction. These bulges were determined to be enveloped by the evaluation performed for the bulge discovered in 1974. These bulges were monitored in 1993 with negligible movement and were considered stable and acceptable, with no further monitoring required.

A review of the summary of the bulged liner plate analysis in the applicant's March 1976 letter and the recent examinations indicate that the bulges are stable and the maximum liner strain associated with the bulged liner is 0.0013, which is less than 40 percent of the strain permissible by Table CC-3720-1 of Division 2 of Section III of the ASME Code. Based on the observations made by the applicant during subsequent pressure tests and inspections, the staff concludes that such bulging will not be detrimental to the containment function during the period of extended operation. However, the staff recommends monitoring of such liner plate bulges during subsequent inspections performed under this program.

The staff's review of the applicant's program implementation process and the method of evaluating containment degradation indicates that the applicant is effectively implementing the AMP and, therefore, the staff finds these actions acceptable.

Section A.3.1.21 of the UFSAR Supplement briefly summarizes the program and makes a note that prior to the start of the extended period of operation, the program will be enhanced to (1) specify the requirements for conducting reexaminations, and (2) document that repairs meet the specified acceptance standards. Neither the LRA nor the UFSAR Supplement states the edition and addenda of the ASME Code being implemented. As amendment of UFSAR is a continuing process, the staff believes it would be appropriate to state the edition and addenda of the ASME Code being used in the UFSAR Supplement. The relief requests granted from the specific edition and addenda of the Code should also be listed in the UFSAR Supplement (and subsequent addenda). The applicant was asked in RAI B.3.13-4 to provide information pertinent to the implementation of the program. By letter dated April 28, 2003, the applicant provided the following response.

> The current code of record for the IWE/IWL Containment Examination Program is the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, 1992 edition through 1992 Addenda, subject to the limitations and modifications of 10 CFR 50.55a(b)(2). The current program comprises the first containment inspection interval and is effective from September 9, 1998 to September 8, 2008. The relief requests are listed in a letter from Herbert N. Berkow (NRC) to D. E. Young (CP&L), titled: "Evaluation of Relief Requests IWE/IWL-1 through IWE/IWL-9: Implementation of Subsections IWE and IWL of ASME Section XI For Containment Inspection for Carolina Power and Light Company's H.B. Robinson Steam Electric Plant, Unit No. 2 (HBRSEP2) (TAC No. MA4637)," dated July 26, 1999. The first Containment Examination Program Interval (2008) ends prior to the extended period of operation (2010). During the extended period of operation, RNP will continue to meet the requirements of the Code incorporated by reference in 10 CFR 50.55a. Therefore, please note that the Code of record and relief requests will change prior to the extended period of operation. In consideration of the above, the information in the first paragraph of LRA Subsection A.3.1.21, ASME Section XI, Subsection IWE Program, is modified to read:
>
> The ASME Section XI, Subsection IWE, Program consists of periodic visual, surface, and volumetric inspection of steel containment components for signs of degradation, assessment of damage, and corrective actions. This program is in accordance with ASME Section XI, Subsection IWE, and in accordance with 10 CFR 50.55a(g), with modifications and approved relief requests.

The applicant provided the requested information about the implementation of Subsection IWE of Section XI of the ASME Code. With the modification noted in the above paragraph, the applicant has properly characterized the scope of the IWE program, and the staff finds the modified paragraph in LRA Subsection A.3.1.21 acceptable.

3.5.2.3.1.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.5.2.3.2 ASME Section XI, Subsection IWL Program

3.5.2.3.2.1 Summary of Technical Information in the Application

The applicant described its ASME Section XI, Subsection IWL Program in Section B.3.14 of the LRA. The LRA states that this program is consistent with GALL Program XI.S2, "ASME Section XI, Subsection IWL," with the following exceptions, (1) RNP did not identify the aging effects of cracking and loss of bond due to corrosion of embedded steel, but did identify loss of material due to the aging mechanism of corrosion of embedded steel and applies the ASME Section XI, Subsection IWL Program, (2) the requirements of ASME Section XI, Subsection IWL, do not apply to the RNP prestressing system because the plant design includes a grouted tendon system, which is outside the scope of Subsection IWL, (3) RNP aging effects/mechanisms include cracking of concrete and change in material properties of concrete due to fatigue at penetration anchors, while these are not addressed in the GALL, (4) erosion of porous concrete subfoundation is not an applicable aging mechanism since porous concrete was not used at RNP under the containment building, and (5) GALL identifies "Increase in porosity, permeability" as aging effects for concrete in Section II.A1, while RNP considers this effect a part of "change in material properties." The applicant credits the ASME Section XI, Subsection IWL Program for aging management of selected components of the reactor containment building at RNP.

The applicant identified the aging effects/mechanisms of concern as (1) change in material properties due to aggressive chemical attack, (2) loss of material due to aggressive chemical attack, (3) loss of material due to corrosion of embedded steel, (4) change in material properties due to fatigue, and (5) cracking due to fatigue.

The applicant further stated that as a result of the license renewal review, administrative controls associated with program element *Scope of Program* will be enhanced to notify Civil/Structural Design Engineering of the location and extent of proposed excavations and to require Civil/Structural Design Engineering to examine representative samples of below-grade concrete when excavated for any reason.

Under the program element "Operating Experience," the applicant states that the program is implemented and maintained in accordance with the general requirements of engineering programs, and asserts that the programs (in general) are effectively implemented through the use of qualified personnel and adequate resources and are managed in accordance with plant administrative controls. Moreover, the applicant makes a point that generic operating experience includes NUREG-1522, "Assessment of Inservice Conditions of Safety Related Nuclear Plant," June 1995, and that RNP was one of the six plants that was inspected in support of this document.

In the plant-specific operating experience, the applicant identified degradation of containment concrete as (1) concrete surface staining, cracking, and spalling at the north and south cable vault rooms, (2) degraded radial construction joint at the base of the crane wall in the area of the ECCS sump, (3) degraded concrete between elevations 226 and 232 ft. on the southwest side of the containment between the equipment hatch and the CV access area (1992), and (4) degradation of grout covering in the dome (1984). For these occurrences, the applicant briefly described corrective actions taken.

The applicant further stated that this AMP is continually upgraded based on the industry experience and research, and that the Corrective Action Program has been effective in ensuring that the ASME Section XI, Subsection IWL Program is continually improving.

3.5.2.3.2.2 Staff Evaluation

In LRA Section B.3.14 , "ASME Section XI, Subsection IWL Program," the applicant described its program to manage aging of containment building components at RNP. The LRA states that this program is consistent with GALL Program XI.S2, "ASME Section XI, Subsection IWL," with the following exceptions, (1) RNP did not identify the aging effects of cracking and loss of bond due to corrosion of embedded steel, but did identify loss of material due to the aging mechanism of corrosion of embedded steel and applies the ASME Section XI, Subsection IWL Program, (2) the requirements of ASME Section XI, Subsection IWL, do not apply to the RNP prestressing system because the plant design includes a grouted tendon system, which is outside the scope of Subsection IWL, (3) RNP aging effects/mechanisms include cracking of concrete and change in material properties of concrete due to fatigue at penetration anchors, while these are not addressed in the GALL, (4) erosion of porous concrete subfoundation is not an applicable aging mechanism since porous concrete was not used at RNP under the containment building, and (5) GALL identifies "increase in porosity, permeability" as aging effects for concrete in Section II.A1, while RNP considers this effect to be part of "change in material properties." The staff confirmed the applicant's claim of consistency during the AMR inspection. Furthermore, the staff reviewed the deviation and its justification to determine whether the AMP, with the deviation, remains adequate to manage the aging effects for which it is credited. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program. In addition, the staff determined whether the applicant properly applied the GALL program to its facility.

The applicant has appropriately described the purpose of the program and the aging effects/mechanisms that will be managed through the implementation of the program. Moreover, the applicant states that administrative controls associated with the program element *Scope of Program* will be enhanced to notify Civil/Structural Design Engineering of the location and extent of proposed excavations and to require Civil/Structural Design Engineering to examine representative samples of below-grade concrete when excavated for any reason. Because of the high acidity of the soil at the plant site, the staff considers the enhancement appropriate.

The staff asked the applicant to provide information regarding the present condition of the below-grade concrete basemat based on the inspections performed during certain maintenance activities. By letter dated April 28, 2003, the applicant provided the following response.

> The soil at Robinson Nuclear Plant is considered aggressive because of the ground water pH being slightly less than 5.5. This is considered to be slightly acidic, rather than highly acidic. Below-grade examinations of concrete have been performed at certain locations with satisfactory results. These include a below-grade section of

the RAB, internal surfaces of electrical manholes exposed to ground water, submerged portions of the intake structure, and the dam spillway exposed to lake water. The lake water environment for the intake structure and dam spillway is essentially the same as that of aggressive ground water (pH values are both below 5.5); as such, inspection results in these areas should envelope aging effects encountered by below-grade concrete of other structures, such as the containment basemat. In addition, an enhancement has already been made to a plant procedure, which requires an examination of any exposed concrete surfaces by engineering prior to backfilling. Please refer to the RNP Response to RAI 3.5.1-3 for more detailed discussion of lake water and ground water chemistry.

Having reviewed the RNPs response to RAI B.3.14-1, the staff requested the applicant to provide a summary of the results of inspections performed (1) in the below-grade sections of the RAB, (2) the submerged portions of the intake structure, and (3) the dam spillway, that would support a conclusion that the below-grade structures have not been degraded, and that the scope of the enhanced inspection is adequate to detect any significant degradation of the below-grade structures during the extended period of operation. The applicant provided the following summary of the results of inspections performed in the (1) below-grade sections of the RAB, (2) submerged portions of the intake structure, (3) dam spillway, and (4) other below-grade concrete.

(1) Below-grade sections of the RAB

A visual inspection of the below-grade portion of the RAB foundation approximately three feet deep was performed in July 1999 while the east foundation was exposed during excavation for construction of the north service water header support slab. This general visual inspection monitored for spalling, scaling, erosion, swelling, bulging, signs of corrosion, cracking, settlement, and exposed rebar. In addition, the interior of Manholes 35 and 36, which abut the RAB, were inspected on September 30, 2002. The interior, which had been exposed to ground water since initial construction, had no signs of spalling or other concrete degradation.

(2) Submerged portion of the Intake Structure

An inspection of the inaccessible areas was performed during Refueling Outage 19 from September 28, 1999, to October 2, 1999, using divers and video equipment. The results of the inspection are as follows. The concrete surface had very little marine growth. There was little or no sediment on the bottom slab. The concrete located at the water line showed signs of erosion from the constant wave action. The top coat of mortar has eroded away leaving the aggregate exposed. The average loss of cover is approximately 1/16 inch to 1/8 inch. The concrete surface was cleaned of marine growth in a number of locations with a wire brush. The top coat came off with minor effort, thereby exposing the aggregate. Sound material was observed at all cleaned locations. Several repairs were observed to have been made in various locations. One repair had flaked off and rebar was observed (one end cut). The repair material thickness was approximately 2 inches and the repair area was about one square foot. This area was determined by the Robinson Engineering Section to have no impact on the structural integrity of the concrete.

(3) Dam Spillway

An underwater inspection was performed June 20, 2000, by divers. The spillway inspection examined the condition of concrete, especially at the tainter gates. A spalled portion of concrete (6" by 8" by 4" deep) was identified. This area is scheduled to be reinspected and repaired prior to the period of extended operation. The Dam Inspection Program will monitor the condition of the normally inaccessible submerged spillway concrete surfaces at a frequency not to exceed 10 years. No other underwater concrete degradation was identified.

(4) Other

The interior of eight security manholes were visually examined in August 2002. The interior concrete has been partially submerged from ground water and provides a similar environment as below-grade concrete (exposure to slightly acidic ground water). No cracking, loss of material, or change in material properties was observed in the concrete surface.

In a conference call with the applicant which occurred on June 16, 2003, the staff pointed out that the applicant did not specify appropriate remedial measures to be followed if the results of RNP's periodic, submerged inspection of the intake structure concrete show significant concrete degradation. Subsequent to this conference call, the applicant, through an e-mail communication, has agreed to the following in order to ensure adequate aging management of below-grade structural concrete that is within the scope of the AMR.

> Degradation to submerged concrete observed during periodic under water inspections at the Intake Structure and RNP Dam Spillway will be used as a leading indicator for potential degradation to below-grade concrete structures in the scope of License Renewal. Below-grade concrete will be evaluated and/or examined for potential degradation and corrective actions taken as determined by Robinson Engineering Support Section. This applies to below-grade concrete examined by the Structures Monitoring Program (SMP) and the ASME Section XI, Subsection IWL Program. Applicable SMP and IWL Program procedures will be enhanced to incorporate these changes.
>
> Ground water and lake water monitoring results (pH, chlorides, sulfates) will be reviewed by Engineering and trended. Increasing aggressiveness of the ground water and lake water will also be used as a leading indicator for potential degradation to below-grade concrete structures in the scope of License Renewal as described above.
>
> Below-grade concrete, when exposed during excavation, already requires notification of Robinson Engineering Support Section for inspection. However, degradation to below-grade concrete due to aggressive ground water, when exposed during excavation, will also be used as a leading indicator for potential degradation to other below-grade concrete structures in the scope of License Renewal as described above.

The staff finds the above commitments adequate to address its concerns regarding the aging management of below-grade, in-scope concrete structural components at RNP. The applicant also committed to provide appropriate documentation of the above agreement. This item was designated as Confirmatory Item 3.5-1. Based on the discussion related to closure of Confirmatory Item 3.5-1 provided in Section 3.5.2.2, "Aging Management Evaluations in the GALL Report That Are Relied On for License Renewal, For Which GALL Recommends Further Evaluation," of this SER, Confirmatory Item 3.5-1 is closed.

Because of the slightly acidic RNP ground water environment, the applicant conservatively assumed existence of an aggressive chemical environment and proposed the above described plant-specific AMPs (an enhanced ASME, Section XI, Subsection IWL Program for containment and an enhanced Structures Monitoring Program for other Category 1 structures) to manage the aging effects of below-grade concrete. As such, the staff finds RAI B.3.14-1 to be fully resolved.

The applicant also described the operating experience related to the degradation of containment concrete, and the evaluation and corrective actions taken. The operating experience related to the containment concrete degradation states, "An evaluation concluded that not providing cooling to the penetrations with hot piping does not degrade the concrete. Degradation has not occurred and does not require augmented examinations." The staff notes that most of the high-temperature-related degradation would be in the concrete around the liner plate (or insert plate). Any degradation occurring in the area cannot be seen by visual examination. Therefore, the staff asked the applicant, in RAI B.3.14-2, to provide information on (1) the sustained temperature in the concrete/liner interface around the hot penetrations, and (2) the use of other NDE examination to ensure that the concrete on the back of the liner is not degraded. By letter dated April 28, 2003, the applicant provided the following information.

> The maximum pipe temperature is 380 °F, and the temperature of the sleeve and concrete was calculated as 208.5 °F. This is conservative, since the calculation assumed 130 °F ambient air over a period of 200 hours. The RHR system is in operation above 200 °F during cooldown for 10 hours, and for 22 hours during the heatup transient. These values are based on plant experience, rather than the 40 hours conservatively assumed in the plant calculation. After 22 hours, the temperature of the sleeve and concrete is at 162.3 °F.
>
> No other examinations have been completed or are planned for the affected concrete, other than those required in accordance with the ASME Section XI, Subsection IWL Program. A concrete surface examination of the area around the applicable RHR penetration (S-15) performed in May 2001 in accordance with the ASME Section XI, Subsection IWL Program identified some notches which had been cut out for small piping routed to the penetration. The inspection found no evidence of in-service degradation, and the inspection results were acceptable.

Additionally, the applicant asserts that the concrete at the RHR penetration meets the design requirements as discussed in the RNP response to RAI 4.6.3-2. The staff reviewed the above in conjunction with the applicant's response to RAI 4.6.3-2. The Code requirements pertinent to the temperatures in concrete are those contained in Subparagraph CC-3440 of Section III, Division 2 of the ASME Code. The requirements permit sustained temperatures up to 200 °F for the concrete around penetrations. The discussion in the applicant's responses indicate that the maximum temperatures around RHR penetration will be 208 °F, for 10 hours during the cooldowns, and 22 hours during heatup transients. Under this type of temperature conditions, the staff believes that the applicant's evaluation related to the concrete compressive strength provided in response to RAI 4.6.3-2 is conservative. The surface inspections performed of the concrete around the penetration did not indicate evidences of inservice degradation. As the applicant will be performing IWL inspections during the extended period of operation, the staff considers the applicant's evaluation of the concrete around the RHR penetration acceptable.

The staff reviewed the exceptions to the GALL Program XI.S2 and concludes that all the plant specific exceptions are reasonable and appropriate.

The staff's review of the applicant's program implementation process and the method of evaluating containment degradation indicate that the applicant is effectively implementing the AMP and the staff finds these actions to be acceptable.

Section A.3.1.22 of the UFSAR Supplement briefly summarizes the program and makes a note that prior to the start of the extended period of operation, the program will be enhanced to (1) specify the requirements for conducting reexaminations, and (2) document that repairs meet the specified acceptance standards. Neither the LRA nor the UFSAR Supplement states the edition and addenda of the ASME Code being implemented. RAI B.3.13-3 pertained to this subject. In its response dated April 28, 2003, the applicant proposed to change the information in the first paragraph of LRA Subsection A.3.1.22, "ASME Section XI, Subsection IWL Program," to include the following.

> The ASME Section XI, Subsection IWL Program consists of periodic visual inspection of concrete surfaces of reinforced and prestressed concrete containments for signs of degradation, assessment of damage, and corrective actions. This program is in accordance with the ASME Code Section XI, Subsection IWL, and addenda in accordance with 10 CFR 50.55a(g), with modifications and approved relief requests. The RNP prestressing tendons are grouted in place. Therefore, ASME Section XI, Subsection IWL rules regarding unbonded post-tensioning systems are not applicable.

The proposed change adequately describes the process to be used for performing inspections in accordance with the ASME Section XI, Subsection IWL Program during the period of extended operation and is acceptable.

3.5.2.3.2.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.5.2.3.3 ASME Section XI, Subsection IWF Program

3.5.2.3.3.1 Summary of Technical Information in the Application

The applicant described its ASME Section XI, Subsection IWF Program in Section B.2.6 of Appendix B of the LRA. The LRA states that this program is consistent with GALL Program XI.S3, "ASME Section XI, Subsection IWF." The applicant stated that the program is credited for aging management of Class 1, 2, and 3 component supports (including piping supports) for loss of material due to general corrosion.

The program is a condition monitoring program that provides for the implementation of ASME Code Section XI, Subsection IWF, in accordance with the provisions of 10 CFR 50.55a. The 10-year examination plan provides a systematic guide for performing NDE of passive components in the scope of license renewal.

Under the program element "Operating Experience," the LRA states that discrepancies found during the visual examination of supports have been transmitted to engineering personnel for evaluation. The LRA also states that the processes at RNP are continually upgraded based upon industry experience, research, and ongoing self-assessments.

3.5.2.3.3.2 Staff Evaluation

In LRA Section B.2.6, "ASME Section XI, Subsection IWF Program," the applicant described its program to manage aging of Class 1, 2, and 3 component supports at RNP. The applicable aging effect is loss of material. The LRA states that this program is consistent with GALL Program XI.S3, "ASME Section XI, Subsection IWF." The staff confirmed the applicant's claim of consistency during the AMR inspection. In addition, the staff determined whether the applicant properly applied the GALL program to its facility. Furthermore, the staff reviewed the UFSAR Supplement to determine whether it provides an adequate description of the revised program.

In Section B.2.6 of the LRA, the applicant identified loss of material due to general corrosion as the only aging effect/mechanism of concern. The program would examine hangers for loss of mechanical function; however, loss of mechanical function was not identified as an age-related degradation in the RNP AMR. In RAI B.2.6-2, the staff asked the applicant to elaborate on the extent to which the component supports are examined for loss of mechanical function and explain why loss of mechanical function for supports was not identified as an age-related degradation in its AMR. The staff also asked the applicant to discuss how its visual examination would be consistent with the GALL IWF program in monitoring or inspecting component supports for corrosion, deformation, misalignment, improper clearances, improper spring settings, damage to close tolerance machined or sliding surfaces, and missing, detached, and/or loosened support items. By letter dated April 28, 2003, the applicant stated that the RNP AMR for the IWF program component supports concluded that the only aging effect/mechanism of concern was loss of material due to general corrosion. The applicant stated that the concerns for loss of mechanical function were addressed in the AMR but their occurrence could not be specifically attributed to aging. The applicant stated that a review of the potential loss of component support intended functions, and the RNP plant reports for component support deficiencies, determined that they could be design related or due to an unplanned plant operational occurrence, but not due to aging. However, the RNP IWF program for component supports currently requires supports to undergo periodic inspections, and the program does examine supports for loss of material due to general corrosion and loss of mechanical function. Although not a requirement for the LRA, the applicant stated that the program examines supports for loss of mechanical function in accordance with Table IWF-2500-1 of Subsection XI (1989 Edition) in the following manner.

- (F1.10) mechanical connections to pressure-retaining components and building structure
- (F1.20) weld connections to building structure
- (F1.30) weld and mechanical connections at intermediate joints in multi-connected integral and nonintegral supports
- (F1.40) clearances of guides and stops, alignment of supports, and assembly of support items
- (F1.50) spring supports and constant load supports
- (F1.60) sliding surfaces
- (F1.70) hot and cold position of spring supports and constant load supports

Because the applicant has committed to manage loss of mechanical function and the information provided above by the applicant resolves the staff's concern regarding the extent of the support examination, the staff finds it acceptable.

The applicant stated that the program provides for VT-3 visual examination for ASME Class 1, 2, and 3 component supports, consistent with GALL requirements. The applicant stated that the operating experience review determined that documentation exists which demonstrates that discrepancies found during the visual examination of supports are transmitted to engineering personnel for evaluation. The visual examinations of ASME Class 1, 2, and 3 component supports look for deformations or structural degradations, corrosion, and other conditions, as stated above, that could affect the intended function of the support. The staff believes that fairly large cracks would be identified for the component supports that are inspected and finds the applicant's VT-3 visual examination to be consistent with GALL and, therefore, acceptable.

The applicant confirmed that this program will be implemented consistently with the requirements of 10 CFR 50.55a throughout the period of extended operation to satisfy the requirements for the aging management of ASME Class 1, 2, and 3 component supports. The LRA states that the program is subject to ongoing self-assessments and, when weaknesses are noted, the Corrective Action Program is used to initiate program improvements. The staff finds that the operating experience supports the applicant's conclusion that the ASME Section XI, Subsection IWF Program is effectively managing aging and is, therefore, acceptable.

The staff reviewed the UFSAR Supplement summary description of the ASME Section XI, Subsection IWF program in Appendix A .3.1.6 of the LRA. The staff finds that the information in the UFSAR Supplement provides an adequate summary of the program activities..

3.5.2.3.3.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.5.2.3.4 10 CFR Part 50, Appendix J Program

3.5.2.3.4.1 Summary of Technical Information in the Application

The applicant's 10 CFR Part 50, Appendix J Program is discussed in Section B.2.7 of the LRA. The LRA states that the program is consistent with GALL Program XI.S4, "10 CFR Part 50, Appendix J." The applicant credits the program for aging management of selected components of the reactor containment building at RNP. The LRA identifies the aging effects/mechanisms of concern as (1) cracking due to elevated temperature, (2) cracking due to thermal fatigue, (3) change in material properties due to elevated temperature, (4) loss of material due to general corrosion, wear, aggressive chemical, crevice corrosion, galvanic corrosion, and pitting.

Under the program element "Operating Experience," the LRA states that the program is implemented in accordance with the general requirements of engineering programs, and that the programs (in general) are effectively implemented through the use of qualified personnel and adequate resources, and are managed in accordance with plant administrative controls. Moreover, the applicant stated that the program is continually upgraded based on industry experience and research. This AMP has provided an effective means of ensuring the structural integrity and leak tightness of the RNP containment. The LRA also states that, in addition to industry experience, plant-operating experiences are shared between CP&L and Florida Power Corporation (FPC) sites through regular peer group meetings.

The applicant provided the following broad statement regarding its operating experience.

> Based on a review of condition reports and inspection results, the corrective action program (CAP) has been effective in ensuring that the Appendix J program is continually improving. Several Condition Reports have been generated as a result of as-found conditions or as a result of assessments (site and corporate). When

weaknesses are noted, actions are taken under the CAP to initiate program improvements. Program improvements were also made as a result of NRC Inspections.

3.5.2.3.4.2 Staff Evaluation

In LRA Section B.2.7, "10 CFR Part 50, Appendix J Program," the applicant described its AMP to manage various components in the reactor containment building. The LRA stated that this program is consistent with GALL Program XI.S4, "10 CFR Part 50, Appendix J," with no deviations. The staff confirmed the applicant's claim of consistency during the AMR inspection. In addition, the staff determined whether the applicant properly applied the GALL program to its facility. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

The staff conceptually considers the Appendix J program as a program to ensure the leak-tight integrity of the containment (as described in GALL Section XI.S4), and the containment ISI program (ASME, Section XI, Subsection IWE Program) as the AMP for detecting the aging degradation of containment pressure boundary components. These programs complement each other and are required to assure that the containment continues to perform its intended functions, as described in Table 2.4-1 of the LRA.

The staff noted that the LRA description of the purpose of the program is not consistent with the program description stated in GALL Program XI.S4. The LRA identified aging effects/mechanisms of concern that cannot be readily detected by performing leakage rate tests as described in GALL Program XI.S4. In RAI B.2.7-1, the staff asked the applicant to provide either a clear description of the purpose of the program that would be consistent with GALL Program XI.S4, or to develop a 10 element program that is consistent with the intended use of the program and an explanation of how the leak-tight integrity of the containment will be maintained during the extended period of operation. By letter dated April 28, 2003, the applicant explained that the implementation of this program detects degradation of the pressure retaining components in conjunction with the implementation of Subsection IWE of Section XI of the ASME Code, and reiterated that the program is consistent with Section XI.S4 of the GALL Report. The staff finds this interpretation of the purpose of the program acceptable.

In RAI B.2.7-2, the staff asked the applicant to clarify which of the options will be used during the extended period of operation, since in the element *Scope of Program* of GALL Section XI.S4, the program provides an option for leakage testing of containment isolation valves either (1) under Appendix J, Type C test, or (2) along with the tests of the systems containing isolation valves. By letter dated April 28, 2003, the applicant provided the following response.

> RNP currently performs Appendix J, Type C tests on containment isolation valves at intervals prescribed by and in accordance with the requirements of 10 CFR 50, Appendix J. While there are no plans to change the method of testing in the near future, the RNP Appendix J Program is continually upgraded based on industry experience and research. Additionally, improved technology or techniques may result in the adoption of different leakage testing techniques during the extended period of operation. Any such changes are expected to involve a license amendment request, or will otherwise be controlled in accordance with 10 CFR 50.59 and/or applicable plant procedures.

The staff recognizes the potential for changes in performing leakage rate testing of containment isolation valves based on the improved technology or techniques, and finds the stated processes that will be utilized for making those changes adequate and acceptable.

The LRA, under *Operating Experience*, states, "Several Condition Reports have been generated as a result of as-found conditions or as a result of assessments (site and corporate)." In RAI B.2.7-3, the staff asked the applicant to provide a summary of condition reports where significant as-found leakages (Type A, Type B, and Type C tests) were found (e.g., more than twice the acceptance criteria), including the corrective action taken. By letter dated April 28, 2003, the applicant stated that a review of the Corrective Action Program database identified no specific conditions where as-found leakages were greater than twice the acceptance criteria. The applicant stated that the as-found conditions cited in the LRA involve generic issues, such as using instruments with the wrong calibrated range, assessment findings of more desirable valve line-ups, or more desirable testing configurations. The applicant also stated that two instances involved findings that containment purge isolation valve V12-8 had exceeded its leakage acceptance criterion by a small margin; however, the condition was resolved by establishing that the original acceptance criterion was overly restrictive. The staff considers the applicant's process for corrective action adequate and acceptable.

The staff reviewed the UFSAR Supplement summary description of the 10 CFR Part 50, Appendix J program in Appendix A .3.1.7 of the LRA. The staff finds that the information in the UFSAR Supplement provides an adequate summary of the program activities.

3.5.2.3.4.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.5.2.3.5 Structures Monitoring Program

3.5.2.3.5.1 Summary of Technical Information in the Application

The applicant described its Structures Monitoring Program in Section B.3.15 of the LRA. The LRA states that this program is consistent with GALL Program XI.S6, "Structures Monitoring Program." The applicant credits this program with aging management of civil SCs within the scope of license renewal. The LRA states that the aging effects and mechanisms of concern include the following.

Steel aging effects and mechanisms

- loss of material due to general corrosion
- loss of material due to crevice corrosion
- loss of material due to pitting corrosion

Concrete (below-grade) aging effects/mechanisms

- loss of material due to aggressive chemical attack
- loss of material due to corrosion of embedded steel
- change in material properties due to aggressive chemical attack

Elastomer aging effects/mechanisms:

- change in material properties due to elevated temperature
- cracking due to elevated temperature

The LRA also identifies a number of enhancements that the applicant will make to its current program (developed for the Maintenance Rule) for the condition monitoring of structures including the following.

- Include buildings and structures, and associated acceptance criteria, in scope for license renewal, but outside the scope of the Maintenance Rule. (Structures addressed in the Maintenance Rule already are in the Program.)

- Identify interfaces between structures monitoring inspections of concrete surfaces and the Fire Protection Program requirements for barriers.

- State clearly the boundary definition between systems and structures. The physical structure is inspected as part of the structure/building walkdown and includes the concrete structure and all structural steel (such as main building—structural steel, platform support steel, stairways, etc.).

- Revise administrative controls to provide inspection criteria for portions of systems covered by structures monitoring. Provide acceptance categories similar to those used for structures monitoring, and require that a condition report be initiated for all inspection attributes found to be unacceptable.

- Expand system walkdown inspection criteria to include observation of selected, adjacent components.

- Revise personnel responsibilities to include responsibilities to (1) provide assistance in evaluating structural deficiencies when requested by the Responsible Engineer, (2) inspect excavated concrete, and (3) notify Civil/Structural Design Engineering of location and extent of proposed excavations.

Under *Operating Experience*, the LRA states that the Structures Monitoring Program is a combination of the existing corporate procedure for condition monitoring of structures and the existing plant procedure for system walkdown, both of which were developed to support implementation of the Maintenance Rule, with the addition of the enhancements described above. The LRA states that the subject administrative controls have been proven effective for implementing the Maintenance Rule and are supported by the excellent operating experience for systems, SCs. The applicant stated that a review of condition reports and inspections performed has concluded that administrative controls are in effect and effective in identifying age-related degradation, implementing appropriate corrective actions, and continually upgrading the administrative controls used for structural monitoring.

3.5.2.3.5.2 Staff Evaluation

In LRA Section B.3.15 , "Structures Monitoring Program," the applicant described its program to manage the aging of civil SCs within the scope of license renewal. The LRA states that this program is consistent with GALL Program XI.S6, "Structures Monitoring Program." The staff confirmed the applicant's claim of consistency during the AMR inspection. In addition, the staff determined whether the applicant properly applied the GALL program to its facility. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

For the aging management of below-grade concrete structural components, the GALL Report recommends that additional measures be taken if an aggressive soil/ground water environment is present. Because RNP has acknowledged an aggressive soil/ground water environment due to a low pH value (< 5.5), the additional measure proposed for the aging management of below-grade concrete is to inspect these components when exposed during plant excavations done for other activities.

As stated in Section 3.5.2.2.1.1 of this SER, the staff found that RNP's approach of inspecting below-grade concrete only when it happens to be exposed during plant excavations done for other activities to be insufficient. As such, the staff requested further measures be taken to ensure the adequate aging management of below-grade concrete at RNP. In response to the staff's concerns, the applicant proposed to use its periodic inspections of the submerged portions of the intake structure and dam spillway as indicators for the condition of below-grade concrete at RNP. Because the ground water and lake chemistry are similar, degradation to submerged concrete will be used as a leading indicator for the potential degradation to below-grade concrete structures. In addition, the applicant committed to modify the Structures Monitoring Program to add this enhancement. This commitment was designated as Confirmatory Item 3.5-1. Based on the discussion related to closure of Confirmatory Item 3.5-1 provided in Section 3.5.2.2, "Aging Management Evaluations in the GALL Report That Are Relied On for License Renewal, For Which GALL Recommends Further Evaluation," of this SER, Confirmatory Item 3.5-1 is closed.

For concrete SCs outside of containment, the applicant stated that it will use the Structures Monitoring Program to manage loss of material and change in material properties. However, the applicant did not indicate that it would manage cracking as specified in the GALL Report. In addition, for several of the table entries in LRA Table 3.5-1, the applicant stated that the aging effect/mechanism combinations identified in the GALL Report are not applicable to RNP. The staff requested, in RAIs 3.5.1-3, 3.5.1-8 , and 3.5.1-11, that the applicant clarify its intent to manage the aging effect/mechanism combinations as recommended by the GALL Report. In response, the applicant stated that although it does not consider these aging effects to be applicable, it will manage the aging of concrete structures at RNP as recommended by the

GALL Report. As the applicant has committed to manage the aging of accessible concrete structural components at RNP, including cracking, the staff considers the response to the RAIs adequate.

The staff requested additional information (RAI B.3.15-2) regarding the aging management of elastomers. By letter dated April 28, 2003, the applicant stated, "The [Structures Monitoring Program] manages aging of the seismic joint filler commodity by visual inspection to note any indication of movement or distress, as well as a determination that the gaps meet design requirements and are free of debris. The [Structures Monitoring Program] manages aging of roof material by a visual inspection for degradation, damage, and/or leakage." The staff finds that this consistent is with GALL and acceptable.

The staff reviewed the UFSAR Supplement summary description of the Structures Monitoring program in Appendix A .3.1.23 of the LRA. The staff finds that the information in the UFSAR Supplement provides an adequate summary of the program activities.

3.5.2.3.5.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that those portions of the program for which the applicant claims consistency with the GALL program are consistent with the GALL program. In addition, the staff has reviewed the exceptions to the GALL program and finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.5.2.3.6 Dam Inspection Program

3.5.2.3.6.1 Summary of Technical Information in the Application

The applicant described its Dam Inspection Program in Section B.3.16 of the LRA. The applicant credits this program for aging management of selected components for Lake Robinson Dam within the scope of license renewal.

The LRA states that the aging effects and mechanisms of concern include the following.

Steel structures aging effects and mechanisms

- loss of material due to general corrosion
- loss of material due to crevice corrosion
- loss of material due to pitting corrosion
- loss of material due to microbiologically induced corrosion

Concrete structures aging effects and mechanisms

- loss of material due to aggressive chemical attack
- loss of material due to corrosion of embedded steel
- change in material properties due to aggressive chemical attack

Earthen structures aging effects and mechanisms:

- loss of form due to settlement

The applicant's program uses the Federal Energy Regulatory Commission FERC/US Army Corps of Engineers program, "Recommended Guidelines for Safety Inspection of Dams," which is one of the acceptable alternatives for managing the aging effects for water control structures documented in GALL, Section III.A6. This is a plant-specific program (e.g., not based on a GALL program), so the applicant described the program using the 10 elements from Appendix A of the SRP-LR.

3.5.2.3.6.2 Staff Evaluation

In LRA Section B.3.16, "Dam Inspection Program," the applicant described its program to manage aging of the Lake Robinson Dam. The program is not based on a GALL program; therefore, the staff reviewed the program using the guidance in Branch Technical Position RLSB-1 in Appendix A of the SRP-LR. The staff's evaluation focused on management of aging effects through incorporation of the following 10 elements from RLSB-1—program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled Quality Assurance Program. The staff's evaluation of the applicant's Quality Assurance Program is provided separately in Section 3.0.4 of this SER and the evaluation of the remaining seven elements is provided below. The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

Program Scope: The LRA indicates that the program covers components of the Lake Robinson Dam and associated concrete structures consistent with the FERC/US Army Corps of Engineers program, "Recommended Guidelines for Safety Inspection of Dams." The staff has accepted the FERC program as a comprehensive program for managing the aging effects of dams. Therefore, the staff finds this acceptable.

Preventive Actions: The LRA states that the Dam Inspection Program is a condition monitoring program; therefore, preventive actions are not required. The staff agrees that the dam inspections are condition monitoring, and the staff had not identified the need for additional preventive actions; therefore, the staff finds this acceptable.

Parameters Monitored or Inspected: The LRA states that the parameters monitored are addressed in detail under Appendix II of "Recommended Guidelines for Safety Inspection of Dams." They include inspection of concrete structures, embankments, spillways, outlet works (gates, channels, sluices, etc.). The staff finds that this is consistent with the FERC program and, therefore, acceptable.

Detection of Aging Effects: The LRA states that the method of identifying aging effects is based on an independent inspection using the "Recommended Guidelines for Safety Inspection of Dams." The detection of aging effects uses a combination of visual field inspection and office review of available data, including records and operating history, to identify any actual or potential deficiencies, whether in the condition of the project works, the quality and adequacy of project maintenance, surveillance, or in the methods of operation. The dam inspections are conducted at five year intervals. The staff finds that this is consistent with the FERC program and, therefore, acceptable.

Monitoring and Trending: The LRA states that the dam inspections are conducted at five year intervals. The LRA further states that the "Recommended Guidelines for Safety Inspection of Dams," Phase I, Appendix 1, investigation report instructs the user to review the "history of previous failures or deficiencies and pending remedial measures for correcting known deficiencies and the schedule for accomplishing remedial measures should be indicated...," and recommends a review of inspection history, including the results of the last safety inspection. The staff finds that the overall monitoring and trending techniques proposed by the applicant are acceptable because inspections and review of inspection history, including the results of the last safety inspection activities, will effectively manage the applicable aging effects.

Acceptance Criteria: The LRA states that the acceptance criteria for the inspection and monitoring of Lake Robinson Dam are in accordance with the requirements of the "Recommended Guidelines for Safety Inspection of Dams," and, as such, will ensure the structure or component intended functions are maintained. The staff finds that this is consistent with the FERC program and, therefore, acceptable.

Operating Experience: The LRA states that five dam inspection reports (five-year intervals starting in 1980) were reviewed, along with a sample of Unit 1 visual inspection reports, yearly South Carolina dam inspections, and a year 2000 underwater visual inspection report for the spillway. Recommendations were made in each report and photographs were taken of typical areas and areas of concern. The LRA states that no significant issues were identified, and that recommended maintenance activities have been performed, as evidenced by succeeding inspection reports. The staff finds that the operating experience supports the applicant's conclusion that the Dam Inspection Program will effectively manage aging of the Lake Robinson Dam.

The staff reviewed the UFSAR Supplement summary description of the dam inspection program in Appendix A .3.1.24 of the LRA. The staff finds that the information in the UFSAR Supplement provides an adequate summary of the program activities.

3.5.2.3.6.3 Conclusions

On the basis of its review of the applicant's program, the staff finds that the program adequately addresses the 10 program elements defined in Branch Technical Position (BTS) RLSB-1 in Appendix A.1 of the SRP-LR, and that the program will adequately manage the aging effects for which it is credited so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 50.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.5.2.4 Aging Management Review of Plant-Specific Structures and Structural Components

In this section of the SER, the staff presents its review of the applicant's AMR for specific structural components. To perform its evaluation, the staff reviewed the components listed in LRA Table 2.4-1 through 2.4-12 to determine whether the applicant properly identified the applicable aging effects and AMPs needed to adequately manage these aging effects. This portion of the staff's review involved identification of the aging effects for each component, ensuring that each component was evaluated in the appropriate LRA AMR Table in Section 3, and that management of the aging effect was captured in the appropriate AMP. The results of the staff's review are provided below.

3.5.2.4.1 Containment

3.5.2.4.1.1 Summary of Technical Information in the Application

The AMR results for the containment are presented in Tables 3.5-1 and 3.5-2 of the LRA. The applicant used the GALL Report format to present its AMR of containment components in LRA Table 3.5-1. In LRA Table 3.5-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect/mechanism, and (4) AMP(s).

As described in Section 2.4.1.1 of the LRA, the containment structure is a steel-lined concrete shell in the form of a vertical right circular cylinder with a hemispherical dome and a flat base. The containment includes the protective concrete structure outside the containment around the personnel and equipment hatch areas. The containment encloses the reactor and major components of the RCS and other important systems that interface with the RCS. Also, the containment houses and supports components required for reactor refueling. These include the polar crane, refueling cavity, and portions of the fuel handling system, which are included with components on the interior of the containment structure.

The materials of construction for the containment structure, as discussed in Section 2.4.1 of the LRA, are concrete, steel, and miscellaneous materials such as containment liner insulation and elastomers. These materials are exposed to containment air, outdoor air, borated water, and a buried environment.

<u>Aging Effects</u>

The LRA identifies the following aging effects for the containment structure.

- cracking, loss of material, and change in material properties for concrete components
- cracking and loss of material for SS penetration sleeves, bellows, and other SS components

- cumulative fatigue for penetration bellows (TLAA)
- loss of material for carbon steel components
- loss of prestress for containment tendons (TLAA)
- change in material properties and cracking for elastomers (results in loss of seal)

Aging Management Programs

The LRA credits the following AMPs with managing the identified aging effects for the containment structure.

- ASME Section XI, Subsection IWL Program
- ASME Section XI, Subsection IWE Program
- ASME Section XI, Subsection IWF Program
- 10 CFR Part 50, Appendix J Program

- Water Chemistry Program
- Structures Monitoring Program
- Boric Acid Corrosion Program
- One-Time Inspection Program
- Inspection of Overhead Heavy Load Handling Systems Program and Light Load Handling Systems
- Fire Water System

A description of these AMPs is provided in Appendix B of the LRA.

3.5.2.4.1.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results—Structures," and the applicable AMP descriptions provided in Appendix B of the LRA, to determine whether the aging effects for the containment components have been properly identified and will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects and the appropriateness of the programs credited for the aging management of the containment structural components at RNP. The staff's evaluation included a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the appropriateness of the AMPs that are credited for managing the identified aging effects for the containment components.

<u>Aging Effects</u>

Concrete: For containment concrete components, the applicant's AMR is consistent with the recommendations in the GALL Report. As such, the applicant has committed to manage cracking, change in material properties, and loss of material for containment concrete components that are accessible. However, for several of the table entries in LRA Table 3.5-1, the applicant stated that the aging effect/mechanism combinations identified in the GALL Report are not applicable to RNP. In RAIs 3.5.1-8, 3.5.1-11, and 3.5.1-14, the staff requested that the applicant clarify its intentions to manage the aging effect/mechanism combinations for concrete SCs as recommended by the GALL Report. In its response to these RAIs, the applicant stated that it has "...committed to an AMP for monitoring accessible concrete based on Interim Staff Guidance." The staff position concerning the aging management of concrete SCs, which is discussed in an Interim Staff Guidance paper for concrete, is that concrete SCs need to be periodically inspected in order to adequately monitor their performance or condition in a manner that allows for the timely identification and correction of degraded conditions. In addition, in response to RAI 3.5.1-8, the applicant stated that Item 10 in LRA Table 3.5-2 will be deleted. Item 10 states that concrete and grout would experience no aging effects. This item includes accessible concrete/grout components located in the containment . Because the applicant has committed to monitor accessible containment concrete/grout components for cracking, loss of material, and change in material properties using the appropriate AMPs, the staff considers the applicant's response to be adequate. As such, the staff considers RAIs 3.5.1-8, 3.5.1-11, and 3.5.1-14 closed.

In RAI 3.5.1-8, the staff requested further information regarding the aging management of the masonry walls in the containment. Item 20 in LRA Table 3.5-1 states that "...the RNP AMR determined that no aging effects are applicable, based on the locations and design of the Masonry Walls at RNP." In its response to RAI 3.5.1-8, the applicant stated that Item 20 in LRA Table 3.5-1 will be changed based on Interim Staff Guidance for concrete aging and that the Structures Monitoring Program will be used to monitor accessible masonry walls for cracking.

For below-grade containment concrete components, the GALL Report recommends aging management only for an aggressive below-grade soil/ground water environment. Since ASME Section XI, Subsection IWL exempts from examination those portions of the concrete containment that are inaccessible, the GALL Report recommends that a plant-specific AMP be developed for concrete that may be exposed to an aggressive below-grade soil/ground water environment. As stated previously in SER Sections 3.5.2.2.1.1 and 3.5.2.2.2.2, the low pH value (< 5.5) for the ground water at RNP suggests a potentially aggressive environment for below-grade concrete. Therefore, a plant-specific AMP, or special provisions to an existing AMP for below-grade concrete components, is warranted. As described previously in Section 3.5.2.2.1.1 of this SER, the applicant has committed to use its periodic underwater inspections at the Intake Structure and RNP Dam Spillway as a leading indicator for potential degradation to below-grade concrete structures. Both these structures are exposed to lake water, which has similar pH, chloride, and sulfate values as the ground water at RNP. In the event that significant degradation to the submerged portions of the Intake Structure or Dam Spillway is observed or ground water and lake water trending results indicate increasing aggressiveness, the applicant will evaluate and examine below-grade concrete through both the ASME Section XI, Subsection IWL (for containment) and Structures Monitoring Program (for other Class I structures) AMPs.

By letter dated August 14, 2003 (RNP Serial RNP-RA/03-0094), the applicant responded to a number of confirmatory items identified by the staff. The staff reviewed the revised contents of Items 25, 26, and 27 of Attachment II (Revised License Renewal Commitments). The staff also reviewed the specific response to Confirmatory Item 3.5-1 provided in Attachment III (Response to License Renewal Confirmatory Items) in the same letter. Based on these reviews, the staff finds that the applicant has provided adequate information, and Confirmatory Item 3.5-1 is closed.

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

Steel: Consistent with the GALL Report recommendations, the applicant identified loss of material for containment carbon steel structural components, cracking, and loss of material as applicable aging effects for steel containment penetrations. In addition, loss of leak tightness in the closed position is identified as an aging effect for the containment equipment hatch and the personnel airlock. The applicant identifies this as loss of material due to wear. Loss of prestress for containment tendons is also identified as an applicable aging effect by the applicant.

Loss of material due to corrosion of the embedded containment liner and cracking of containment penetrations due to cyclic loading are identified by the GALL Report as aging effects requiring further evaluation and are covered in detail in Sections 3.5.2.2.1.4 and 3.5.2.2.1.7, respectively, of this SER. Loss of prestress for containment tendons is evaluated as a TLAA and reviewed by the staff in Section 4.5 of this SER. Fatigue damage is evaluated as a TLAA in Section 4.3.5 of this SER.

For carbon steel components that are completely encased in concrete (i.e., penetration sleeves, liner plate, airlock and hatch penetrations, anchorages/embedments, floor drains, and grouted tendons), the applicant did not identify loss of material as an applicable aging effect. In RAI 3.5.1-2, the staff requested that the applicant justify its conclusion regarding the aging management of the above components. In response to RAI 3.5.1-2, the applicant stated the following.

> The basis for determining that carbon steel components completely encased in RNP concrete would experience no loss of material aging effect includes consideration of the concrete design, in combination with the highly alkaline environment of concrete, and no plant operating experience identifying corrosion of embedded steel as an issue. Section 3.8.1.6.1.2 of the UFSAR states: "All reinforcing steel and frames which form an extension of the reinforcing steel are encased completely within the highly alkaline environment of the concrete wall and dome and are, therefore, protected from corrosion." Section 3.8.1.6.1.3 of the UFSAR states: "Concrete has been used successfully for many years as a protective covering for steel." As specified in NUREG-1557, and referenced in the GALL, the attributes of a concrete design for which corrosion is not significant are the same as specified for the RNP concrete design, specifically the concrete design is per ACI 318-63 with a low water-to-cement ratio and adequate air entrainment. Plant operating experience supporting this position is found in the corrosion inspection reports for the grouted surveillance tendons, which notes in the conclusions: "Based upon the results of the investigations documented in this report, it is concluded that there is no significant corrosion in the Robinson Nuclear Power Plant 25-year containment surveillance block provided for investigation." Additionally, the absence of any deficiencies identified in the Corrective Action Program, associated with the loss of material from embedded components, provides further evidence that the aging effect is not credible for the subject components. A combination of all the attributes listed in the above discussion provides reasonable assurance that carbon steel components completely encased in RNP concrete would experience no loss of material aging effect.

Based on the RNP concrete design, which is ACI Code compliant, RNP's plant-specific operating experience, and the highly alkaline environment of the concrete that encases the carbon steel components, the staff finds the potential for significant loss of material is not likely. As such, the staff considers RAI 3.5.1-2 to be closed.

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

Elastomers (moisture barriers, seals): Consistent with the GALL Report recommendations, the applicant identified loss of seal as an applicable aging effect for the containment moisture barrier and seals/gaskets. The aging effects identified by the applicant are change in material properties and cracking of elastomers. These aging effects are considered to result in loss of seal.

Item 6 of LRA Table 3.5-1, states that the leak tightness of seals and gaskets of containment penetrations is ensured by means of an Appendix J program. Performance based Option B of Appendix J (of 10 CFR 50) provides flexibility to the users of the option to perform Type B tests at an interval as long as 10 years (except for the air locks). Considering that some leakage is allowed during the type B tests (i.e., minor degradation is permissible), RAI 3.5.1-18 requested that the applicant discuss how it will manage the degradation of penetration seals and gaskets between the test intervals during the extended period of operation. In response to RAI 3.5.1-18, the applicant stated the following.

> RNP uses Option A of 10 CFR 50, Appendix J, for Type B testing (for gaskets and seals). Type B tests are conducted on a refueling outage interval, not to exceed a maximum interval of two years with the following exceptions: 1. The containment air lock is tested at six-month intervals. 2. If the air lock is opened during periods when containment integrity is not required, it is tested at the end of such periods prior to restoring the reactor to an operating mode that requires containment integrity. 3. If the air lock is opened during periods when containment integrity is required, the door seals are tested within 3 days after being opened. This current frequency of testing was evaluated to be adequate for the extended period of operation. Due to the short testing intervals, credit was not taken for additional inspections made as part of preventative maintenance. The Appendix J Program at RNP is consistent with GALL Section XI.S4, as discussed in LRA Appendix B, Item B.2.7.

Since the applicant is using Option A of 10 CFR 50, Appendix J, for Type B testing for managing the degradation of penetration seals and gaskets, which requires more frequent testing than Option B, the staff finds the proposed aging management adequate and reasonable and considers RAI 3.5.1-18 closed.

The staff finds the applicant's approach for evaluating the applicable aging effect for elastomers in containment to be reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effect for elastomers in containment.

Miscellaneous Materials (copper alloy, bronze/graphite, insulation): For the bronze sliding bearing plates and threaded fasteners, copper alloy components, and insulation materials located in containment, the applicant did not identify any aging effects. In RAI 3.5.1-6, the staff requested that the applicant justify the above conclusion for each of these materials. In response to RAI 3.5.1-6, the applicant stated the following.

> The slide bearing plates identified in Item 13 of LRA Table 3.5-2 are fabricated from copper alloys (bronze material) impregnated with a graphitic lubricant with the trade name Lubrite or Lubron. Item 13 was used to categorize the copper alloy component or bronze material. Item 14 of LRA Table 3.5-2 was used to categorize the miscellaneous component or the graphite based lubricant. ASM Handbook, Volume 13, Corrosion – page 617, describes the corrosive ratings for various copper alloys in boric acid as "Excellent: resists corrosion under almost all conditions of service." Additionally, past ISI inspection reports for the reactor coolant pump supports and steam generator supports have identified no recordable degradation of the slide bearing plates. Based on the above, there is reasonable assurance that the subject item will experience no credible aging effects requiring an AMP.
>
> The containment liner insulation is fabricated from a PVC or polyamide foam. The subject insulation is used for thermal insulation of the containment liner, and is in direct contact with the external surface of the liner on one side, and is covered with a stainless steel sheathing (sheet metal) on the other side. There have not been specific inspections performed for the insulation panels, but, inspection reports for liners have not identified age related degradation of the insulation, and no condition reports have been identified that are associated with liner insulation degradation. Therefore, based on an absence of age related degradation operational experience, there is reasonable assurance that the containment liner insulation will experience no credible aging effects requiring an AMP.
>
> The containment penetration insulation commodities are identified as high density penetration insulation (BTU-BLOCK Flexible by Manville) and fiberglass blankets for the main steam lines, and ceramic fiber insulation for the steam generator blowdown lines. The subject insulation is located in the containment air environment not subject to boric acid leaks. No aging effects have been identified based on review of RNP operating experience, and based on the protective location of the subject insulation (inside penetrations), no mechanical degradation is expected. Therefore, no aging effects are identified that require management and an AMP is not required.

Since the applicant's previous operating experience with the materials identified above demonstrates that there are no applicable aging effects, the staff finds the applicant's response to RAI 3.5.1-6 adequate.

The staff finds the applicant's approach for evaluating the applicable aging effect for miscellaneous materials in containment to be reasonable and acceptable. The staff concludes that the applicant has properly evaluated the potential aging of miscellaneous materials in containment.

On the basis of its review, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the containment.

Aging Management Programs

Tables 3.5-1 and 3.5-2 of the LRA credit the following AMPs with managing the identified aging effects for the components in the containment.

- ASME Section XI, Subsection IWL Program
- ASME Section XI, Subsection IWE Program
- ASME Section XI, Subsection IWF Program

- Structures Monitoring Program
- Boric Acid Corrosion Program
- One-Time Inspection Program
- 10 CFR Part 50, Appendix J Program
- Water Chemistry Program

The Boric Acid Corrosion Program, Water Chemistry Program, and One-Time Inspection Program are credited with managing the aging of several components in several different structures and systems and are, therefore, considered common AMPs. The staff's review of these common AMPs can be found in Section 3.0.3 of this SER. The staff's evaluation of the noncommon, or structure-specific, AMPs, listed above, is presented in Section 3.5.2.3 of this SER. Two additional AMPs manage aging effects for containment components, but are not identified in Table 3.5-1 or Table 3.5-2. The Inspection of Overhead Heavy Load and Light Load Haandling Systems Program is reviewed in Section 3.3.2.3.1 of this SER. The Fire Water System Program is reviewed in Section 3.3.2.3.3 of this SER.

After evaluating the applicant's AMR for each of the components in the containment, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.5-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.5-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with containment. In addition, the staff found the associated program descriptions in the UFSAR Supplement to be acceptable.

The staff has reviewed the information in Sections 2.4 and 3.5 of the LRA, the applicant's responses to the staff's RAIs, and the applicable AMP descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the containment components will be adequately managed so that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5.2.4.2 Other Structures

3.5.2.4.2.1 Summary of Technical Information in the Application

The AMR results for other structures are presented in Tables 3.5-1 and 3.5-2 of the LRA. The applicant used the GALL Report format to present its AMR of structural components in LRA Table 3.5-1. In LRA Table 3.5-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s). The structural components listed in Tables 3.5-1 and 3.5-2 of the LRA are in the following structures.

- Reactor Auxiliary Building
- Fuel Handling Building
- Turbine Building
- Dedicated Shutdown Diesel Generator Building
- Radwaste Building
- Intake Structure
- North Service Water Header Enclosure
- Emergency Operations Facility/Technical Support Center Security Emergency Diesel Generator Building
- Lake Robinson Dam
- Pipe Restraint Tower
- Yard Structures and Foundations

A brief description of each of the above structures is provided in Section 2.4.2, "Other Structures," of the LRA. The materials of construction identified in the LRA for each of the above structures are (1) steel, (2) concrete, (3) aluminum, (4) elastomers, and (5) miscellaneous material, such as soil and ceiling and floor tiles. These materials are exposed to outdoor, buried, indoor air-conditioned, indoor not-air-conditioned, borated water, and raw water environments.

The spent fuel storage racks, neutron absorbing sheets in spent fuel storage racks and cranes including bridge and trolleys and rail system in load handling systems are scoped under structures. The AMR results of these structural components are presented in Tables 3.3-1 and 3.3-2 of the LRA.

Aging Effects

Tables 3.5-1 and 3.5-2 of the LRA identify the following applicable aging effects for components in structures outside the containment.

- loss of material
- change in material properties and cracking of elastomers
- cracking
- loss of mechanical function
- loss of form
- corrosion of embedded steel
- reduction in concrete anchor capacity
- cracking of masonry walls

Aging Management Programs

Tables 3.5-1 and 3.5-2 of the LRA credit the following AMPs with managing the identified aging effects for the components in structures outside the containment.

- ASME Section XI, Subsection IWF Program
- Boric Acid Corrosion Program
- Dam Inspection Program
- Structures Monitoring Program
- Water Chemistry Program

The applicant credited the above listed Water Chemistry Program to manage the loss of material aging effect of the spent fuel storage racks. The applicant credits Inspection of Overhead Heavy Load and Light Load Handling System Program to manage aging effects of RNP cranes and their related components.

A description of these AMPs is provided in Appendix B of the LRA.

3.5.2.4.2.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results—Structures," and the applicable AMP descriptions provided in Appendix B of the LRA to determine whether the aging effects for components in structures outside the containment have been properly identified and will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects and the appropriateness of the programs credited for the aging management of structures outside the containment at RNP. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the appropriateness of the AMPs that are credited for managing the identified aging effects for the components in structures outside the containment.

Aging Effects

Concrete: For concrete components in structures outside the containment, the applicant's AMR is consistent with the recommendations in the GALL Report. As such, the applicant has committed to manage cracking, change in material properties, and loss of material for concrete structural components that are accessible. As stated previously in Section 3.5.2.4.1.2 of this SER, several of the table entries in LRA Table 3.5-1 stated that the aging effect/mechanism combinations identified in the GALL Report are not applicable to RNP. The staff requested, in RAIs 3.5.1-8 and 3.5.1-10 , that the applicant clarify its intent to manage the aging effect/mechanism combinations as recommended by the GALL Report. In response, the applicant stated that although it does not consider these aging effects to be applicable, it will manage the aging of concrete structures at RNP as recommended by the GALL Report. As the applicant committed to manage the aging of accessible concrete structural components at RNP, the staff considers the response to the RAIs adequate.

For below-grade concrete structural components, the GALL Report recommends aging management only for an aggressive below-grade soil/ground water environment. Item 17 of LRA Table 3.5-1 states the following.

> The aging mechanisms associated with aggressive chemical attack and corrosion

of embedded steel are applicable only to below-grade concrete/grout structures owing to the slightly acidic pH of ground water. The Structures Monitoring Program is applicable to these structures. RNP will apply a special, plant-specific inspection provision to monitor aging effects caused by aggressive chemical attack and corrosion of embedded steel for below-grade concrete in this component/commodity group. This will include inspection of below-grade concrete and grout that is exposed during excavation. These aging management activities are consistent with the GALL Report.

As stated previously in SER Sections 3.5.2.2.1.1 and 3.5.2.2.2.2, the low pH value (< 5.5) for the ground water at RNP suggests a potentially aggressive environment for below-grade concrete. Therefore, a plant-specific AMP, or special provisions to an existing AMP for below-grade concrete components is warranted. The provision proposed above by the applicant is to include inspection of below-grade concrete and grout that is exposed during excavation as part of the Structures Monitoring Program. As stated previously in Section 3.5.2.2.1.1 of this SER, the staff found the RNP's approach of inspecting below-grade concrete only when it happens to be exposed during plant excavations done for other activities to be insufficient. As such, the staff requested that further measures be taken to ensure the adequate aging management of below-grade concrete at RNP. As described previously in Section 3.5.2.2.1.1 of this SER, the applicant has committed to use its periodic underwater inspections at the intake structure and RNP dam spillway as a leading indicator for potential degradation to below-grade concrete structures. Both these structures are exposed to lake water, which has similar pH, chloride, and sulfate values as the ground water at RNP. In the event that significant degradation to the submerged portions of the intake structure or dam spillway is observed, the applicant will evaluate and examine below-grade concrete through both the ASME Section XI, Subsection IWL (for containment) and Structures Monitoring Program (for other Class I structures) AMPs. The applicant's commitment to provide appropriate documentation of the above agreement was designated as Confirmatory Item 3.5-1. Based on the discussion related to closure of Confirmatory Item 3.5-1 provided in Section 3.5.2.2, "Aging Management Evaluations in the GALL Report That Are Relied On for License Renewal, For Which GALL Recommends Further Evaluation," of this SER, Confirmatory Item 3.5-1 is closed.

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

Steel: Consistent with the recommendations of the GALL Report, the applicant identified loss of material as an applicable aging effect for carbon steel components in structures outside the containment. This includes all Class I structures identified in the GALL Report.

For some of the carbon steel structural components listed in Section 2.4, "Scoping and Screening Results—Structures," the staff was unable to verify that the aging effect(s) identified for these components in Table 3.5-1 of the LRA will be managed by an appropriate AMP. In RAI 3.5.1-13, the staff requested the applicant to provide clarification regarding the AMR conclusions for carbon steel structural components inside containment, as well as for structures outside containment.

In response to RAI 3.5.1-13, the applicant stated the following.

> Loss of material is an applicable aging effect for carbon steel components inside or outside containment and is managed by one of the following programs for the structural components listed in Section 2.4.
>
> - Structures Monitoring Program
> - Boric Acid Corrosion Program
> - IWF Program
> - IWE Program
> - Appendix J Program
> - One-Time Inspection Program
> - Dam Inspection Program
>
> These AMPs are considered to be appropriate for managing the aging effects for carbon steel components that were identified in the AMR.

As the applicant has clarified its intention to manage loss of material for carbon steel structural components, as recommended by the GALL Report, the staff finds the applicant's response to RAI 3.5.1-13 adequate.

For below-grade carbon steel foundation pilings, the applicant identified corrosion of the piles as a TLAA and performed an evaluation for a 40-year corrosion loss. The staff's evaluation of this TLAA is found in Section 4.6.2 of this SER.

For SS components, the applicant identified loss of material as an applicable aging effect for (1) liners in the fuel storage facility and refueling canal, (2) the fuel transfer tube and associated bellows, and (3) detector and manway cover, spent fuel racks, and reactor cavity seal ring plate. In Table 3.5-1 of the LRA, the applicant indicated that stress- corrosion cracking is not applicable for the SS reactor cavity or spent fuel pool liners. The applicant stated that cracking due to SCC requires both high temperatures (> 140 °F) and exposure to an aggressive environment to be applicable. Because the normal temperatures in the fuel pool and reactor cavity do not exceed 140 °F, the applicant concluded that SCC is not applicable. As the applicant's position is consistent with the GALL Report, the staff concurs with this position.

The AMR results of Neutron absorbing sheets in spent fuel storage racks are provided on LRA Table 3.3-1. Section 4.6.4.2 of this SER discusses staff evaluation for the Boraflex degradation and the related Confirmatory Item 4.6.4-1. By letter dated December 22, 2003, License Amendment No. 198, the staff approved the applicant's request to eliminate the need to credit the Boraflex neutron absorbing material for reactivity control in the spent fuel storage pool. In place of the Boraflex material (i.e., panels), the staff approved the applicant's request to take credit for a combination of soluble boron and controlled fuel loading patterns in the spent fuel pool to maintain the required subcriticality margins in the spent fuel storage pool. On the basis of the final issuance of License Amendment No. 198, the staff finds that Confirmatory Item 4.6.4-1 is closed.

With regard to the AMR of spent fuel storage racks, the applicant concluded that stress corrosion cracking was not applicable to RNP spent fuel storage racks, because the temperature of the fluid is normally less than 140 degree F. However, the applicant determined that loss of material due to crevice and pitting corrosion is an applicable aging effect for spent fuel storage racks. The applicant credits Water Chemistry Program to manage this aging effect. The staff finds the above RNP determination adequate and acceptable.

The applicant identified general corrosion, but not wear, as an aging mechanism for crane rails. The applicant also stated that regardless of the aging mechanism, Inspection of Overhead Heavy Load and Light Load Handling Systems Program is credited to manage loss of material aging effect for in-scope cranes including bridge and trolleys and rail system in load handling systems. The staff finds this RNP position adequate and acceptable.

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

Elastomers: For the structures outside containment, the applicant identified change in material properties and cracking from elevated temperature as applicable aging effects in Table 3.5-2 of the LRA. The applicant credited the Structures Monitoring Program to manage these two aging effects of elastomeric material.

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

Miscellaneous materials: The in-scope miscellaneous materials identified by the applicant in structures outside the containment are soil for the Lake Robinson earthen dam, and ceiling and floor tiles for the control room.

For the Lake Robinson earthen dam, the applicant identified loss of form due to settlement as an applicable aging effect and proposed to use its Dam Inspection Program. The identification of loss of form as an applicable aging effect for earthen embankments or dams is consistent with the GALL Report. In addition, the applicant's Dam Inspection Program is a FERC/US Army Corps of Engineers program, which is also consistent with the GALL Report.

No aging effects were identified by the applicant for the floor and ceiling tiles in the control room. In RAI 3.5.1-6, the staff requested further information regarding the previous operating experience for these components. In response, the applicant provided the following information.

> For the control room, ceiling the acoustical ceiling tiles are mineral fiberboard, manufactured by Armstrong. The suspended grid system for the acoustical tile is a heavy duty exposed tee system by Armstrong. The control room ceiling is supported by a combination of structural steel, threaded rod, and unistrut attached to the building by welding or expansion bolts. The material is either coated steel or galvanized steel. The control room raised floor access floor system is constructed of epoxy painted carbon steel pedestals, stringers, and floor panels furnished by Tate Access Floors, Inc. Fasteners are either carbon steel or galvanized steel. The cable spread room raised floor access floor system is constructed of epoxy painted

carbon steel pedestals, stringers, and perforated floor panels furnished by Tate Access Floors, Inc. Fasteners are either carbon steel or galvanized steel. The control room and cable spreading room are indoor-air-conditioned environments. Therefore, the carbon steel structural supports for the control room and cable spreading room raised floors do not require aging management. Additionally, based on RNP operating experience, no aging effects requiring management for the control room ceiling material or raised floors have been identified. Therefore, no AMP is required.

Because the applicant has not identified any previous aging of the floor and ceiling tiles and because these tiles are in an air-conditioned indoor environment, the staff concurs with the applicant 's conclusion that there are no applicable aging effects. As such, RAI 3.5.1-6 is closed.

On the basis of its review, the staff finds the applicant has identified the appropriate aging effects for the materials and environments associated with the structures outside the containment.

Aging Management Programs

Tables 3.5-1and 3.5-2 of the LRA credit the following AMPs with managing the identified aging effects for the components in structures outside the containment.

- ASME Section XI, Subsection IWF Program
- Boric Acid Corrosion Program

- Dam Inspection Program
- Structures Monitoring Program
- Water Chemistry Program

The applicant credits the above listed AMPs to manage the aging effects associated with structures and structural components outside the containment. Two AMPs (i.e., Water Chemistry Program and Boric Acid Corrosion Program) are common AMPs, while the remaining three AMPs are credited with managing aging only for structures and structural components outside the containment. The staff's evaluation of the common AMPs credited with managing aging in structures and structural components outside the containment is provided in Section 3.0.3 of this SER.

Table 3.3-1 of the LRA credits Inspection of Overhead Heavy Load and Light Load Handling Systems Program with managing of the identified aging effects for cranes including bride and trolleys and rail system in load handling systems. The staff evaluation of this crane inspection program is provided in SER Section 3.3.2.3.1.2.

Other structural components are managed by additional AMPs. These AMPs and locationwhere the staff evaluated these AMPs are listed below:

- Fire Water System Program (SER Section 3.3.2.3.3)
- Fire Protection System Program (SER Section 3.3.2.3.2)
- Preventive Maintenance Program (SER Section 3.0.3.12)

- Inspection of Overhead Heavy Load and Light Load Handling System Program (SER Section 3.3.2.3.1)

Additional staff evaluation of the structural components outside the containment can be found in the applicable technical evaluations provided in Section 3.5.2.2.2 of this SER.

After evaluating the applicant's AMR for each of the components in structures outside the containment, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.5-1 of the LRA, the staff verified that the applicant credited the AMP recommended by the GALL Report. For the components identified in LRA Table 3.5-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplements provide adequate program descriptions of the AMPs credited for managing aging in structures and structural components outside the containment.

The staff has reviewed the information in Sections 2.4 and 3.5 of the LRA, the applicant's responses to the staff's RAIs, and the applicable AMP descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in structures outside the containment will be adequately managed so that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5.2.4.3 Component Supports

3.5.2.4.3.1 Summary of Technical Information in the Application

The AMR results for the component supports are presented in Tables 3.5-1 and 3.5-2 of the LRA. The applicant used the GALL Report format to present its AMR of the components in LRA Table 3.5-1. In LRA Table 3.5-2, the applicant identified the component group designation along with its (1) material, (2) environment, (3) aging effect(s), and (4) AMP(s).

Component supports are those components that provide support or enclosure for mechanical and electrical equipment. The component supports identified in LRA Section 2.4 include (1) anchorages/embedments, (2) electrical component supports, (3) expansion anchors, (4) instrument line supports, (5) instrument racks and frames, (6) pipe supports, (7) pressurizer surge line supports, (8) SG supports, (9) vibration isolators, (10) battery racks, (11) HVAC duct supports, (12) tube track supports, and (13) several other supports .

The materials of construction for the component supports, which are subject to an AMR, are steel, and copper alloy. These materials are exposed to internal, external, borated water leaks, and embedded environments.

<u>Aging Effects</u>

Tables 3.5-1 and 3.5-2 of the LRA identify the following applicable aging effects for the component supports.

- loss of material
- cracking
- loss of mechanical function

Aging Management Programs

Tables 3.5-1 and 3.5-2 of the LRA credit the following AMPs with managing the identified aging effects for the component supports.

- Boric Acid Corrosion Program
- Structures Monitoring Program
- ASME Section XI, Subsection IWF Program

A description of these AMPs is provided in Appendix B of the LRA.

3.5.2.4.3.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results—Structures," and the applicable AMP descriptions provided in Appendix B of the LRA to determine whether the aging effects for the component supports have been properly identified and will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's AMR for the aging effects and the appropriateness of the programs credited for the aging management of the component supports at RNP. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the appropriateness of the AMPs that are credited for managing the identified aging effects for the component supports.

Aging Effects

Steel: Consistent with the recommendations of the GALL Report, the applicant identified loss of material as an applicable aging effect for the carbon steel component supports in non-air-conditioned environments (internal and external). For SS component supports, either in an outdoor or borated water environment, the applicant identified loss of material as an applicable aging effect. In addition, for galvanized steel component supports in an outdoor environment, the applicant also identified loss of material as an applicable aging effect.

However, for galvanized structural steel in indoor, containment air, or exposed to borated water leaks, Items 2 and 11 of LRA Table 3.5-2 state that there are no applicable aging effects. In RAI 3.5.1-5, the staff requested that the applicant discuss past incidents of borated water leakage including ponding of leaked borated water at RNP. Additionally, Item 12 of LRA Table 3.5-2 states that there are no applicable aging effects for SS threaded fasteners (among other SS components). As part of RAI 3.5.1-5, the staff also requested that the applicant confirm that there are no SS threaded fasteners used in a wetted or highly moist air environment. In response to RAI 3.5.1-5, the applicant stated the following.

For galvanized steel, no operating experience examples were identified regarding borated water leaks causing aging to the galvanized steel components identified in LRA Table 3.5-2, items 2 and 11. As a conservative measure, RNP has decided to include loss of material due to corrosion for galvanized steel in a borated water leakage environment as an aging effect/mechanism. As such, borated water leakage environment should be deleted as an applicable environment in LRA Table 3.5-2, Item 2. In addition, galvanized steel should be deleted as a material and from the discussion column of LRA Table 3.5-2, Item 11. In LRA Table 3.5 -1, Item 16, the discussion column for steel should include galvanized steel.

For stainless steel, no operating experience examples were identified regarding borated water leaks causing aging to the stainless steel components identified in LRA Table 3.5 -2, Items 2 and 11. At RNP, LR did not identify occurrences of stainless steel threaded fasteners in a wetted or highly moist environment.

Because the applicant has committed to manage loss of material, due to corrosion, for galvanized steel components in a borated/water leakage environment and because the applicant did not identify any occurrences of SS threaded fasteners in a wetted environment, the staff finds the applicant's response to RAI 3.5.1-5 adequate.

For the high strength carbon steel threaded fasteners, the applicant did not identify cracking due to SCC as an applicable aging effect. Item 29 of LRA Table 3.5-1 states the following.

The RNP AMR, which included operating experience, determined that SCC is not an applicable aging mechanism for RNP bolting. In general, high strength structural bolting, i.e., bolting with specified yield strength > 150 ksi, is not being used; and, for the one case where high strength bolts have been installed, the environment experienced by the bolts is considered benign with respect to SCC, i.e., the bolts are located in a dry environment high up on the steam generator above any source of leakage and, therefore, not exposed to an aggressive or aqueous environment. Based on these results, no AMP is required to manage cracking due to SCC.

Conditions that may contribute to the occurrence of SCC for high strength carbon steel threaded fasteners are elevated temperatures, an aggressive environment (e.g., borated water leaks), and wetted air with an oxygen concentration. For the one case where high strength bolting is used at RNP, the applicant stated that none of these conditions are prevalent. As such, the staff concurs with the applicant that SCC is not an applicable aging effect for high strength carbon steel threaded fasteners.

Item 28, Table 3.5-1, of the LRA states that RV nozzle supports are inaccessible and not currently inspected under the RNP ASME Section XI, Subsection IWF Program and that RNP plans to implement an inspection under the One-Time Inspection Program to verify effective management of potential corrosion of the supports. RAI 3.5.1-1 requested that the applicant discuss the specific steps to be adopted in performing the one-time inspection of the inaccessible nozzle supports and provide the basis for concluding that a one-time inspection would suffice to ensure effective aging management of these inaccessible supports. The applicant provided the following response to RAI 3.5.1-1.

> RNP has elected to remove the RV nozzle supports from the One-Time Inspection Program and will include them within the ASME Section XI, Subsection IWF Program. Therefore, a RV nozzle support will be inspected by the IWF Program during the Fourth Ten-Year ISI Interval prior to the end of the current 40-year Operating License. Due to the limited accessibility of the supports, a limited visual inspection will be made using remote visual technology. The RV nozzle supports will continue to be inspected by the ASME Section XI, Subsection IWF Program during the period of extended operation. A review of operating experience (OE) indicated a condition report was identified in April 2001 (during Refueling Outage-21). This OE information was a consideration in the decision to include the RV nozzle supports in the ASME Section XI, Subsection IWF Program.

Because the applicant has committed to periodic inspections of the RV nozzle supports through the ASME Section XI, Subsection IWF Program, rather than a single inspection under the One-Time Inspection Program, the staff finds the above response adequate and RAI 3.5.1-1 closed.

Copper Alloy: For the copper alloy slide bearing plate inside containment, the applicant did not identify any applicable aging effects. The staff's review of these slide bearing plates is provided in Section 3.5.2.4.1.2 of this SER.

On the basis of its review, the staff finds that the applicant has identified the appropriate aging effects for the materials and environments associated with component supports.

Aging Management Programs

Tables 3.5-1 and 3.5-2 of the LRA credit the following AMPs with managing the identified aging effects for the component supports.

- Boric Acid Corrosion Program
- Structures Monitoring Program
- ASME Section XI, Subsection IWF Program

The Boric Acid Corrosion Program, Bolting Integrity Program, and One-Time Inspection Program are credited with managing the aging of several components in several different structures and systems and are, therefore, considered common AMPs. The staff's review of these common AMPs can be found in Section 3.0.3 of this SER. The staff's evaluation of the noncommon or structure-specific AMPs, listed above, is provided in Section 3.5.2.3 of this SER.

After evaluating the applicant's AMR for each of the components in the containment, the staff evaluated the AMPs listed above to determine if they are appropriate for managing the identified aging effects. For those components identified in Table 3.5-1 of the LRA, the staff verified that the applicant credited the AMPs recommended by the GALL Report. For the components identified in LRA Table 3.5-2, the staff verified that the applicant credited an AMP that is appropriate for the identified aging effect(s).

On the basis of its review, the staff finds the applicant has credited the appropriate AMPs to manage the aging effects for the materials and environments associated with the component supports. In addition, the staff found the associated program descriptions in the UFSAR Supplement to be acceptable.

3.5.2.4.3.3 Conclusions

On the basis of its review, the staff concludes that, the applicant has adequately identified the aging effects, and the AMPs credited for managing the aging effects, of the containment, structures, and component supports plant specific components in Sections 3.5.2.4.1 through 3.4.2.4.3, such that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR Supplement program description and concludes that it provides an adequate program description of the AMPs credited for managing aging of the containment, structures, and component supports plant specific components, as required by 10 CFR 54.21(d).

3.5.3 Evaluation Findings

The staff has reviewed the information in Section 3.5 of the LRA. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the containments, structures, and component supports, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation. The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited for managing aging effects, as required by 10 CFR 54.21(d).

3.6 Electrical and Instrumentation and Controls

This section addresses the aging management of the components of the electrical and instrumentation and control (I&C) systems group. The systems that make up this group are described in the following LRA sections:

- Bus Duct (2.5.3.1)
- Insulated Cables and Connections (2.5.3.2)
- Electrical/Instrumentation and Control Penetration Assemblies (2.5.3.3)

As discussed in Section 3.0.1 of this SER, the electrical and instrumentation and controls are included in one LRA table. LRA Table 3.6-1 consists of electrical and I&C components that are evaluated in the GALL Report.

3.6.1 Summary of Technical Information in the Application

In LRA Section 3.6, the applicant described its AMRs for the electrical and I&C systems group at RNP.

The applicant stated that the methodology used for AMR of this system group employs the "plant spaces" approach in which the plant is segregated into areas (or spaces) where common bounding environmental parameters can be assigned. Each bounding environmental parameter is evaluated against the most limiting (worst-case) material in the area to determine if the components will be able to maintain their intended functions through the period of extended operation.

The Department of Energy (DOE), "Aging Management Guideline for Commercial Nuclear Power Plants—Electrical Cable and Terminations," (the Cable AMG) was used to identify aging effects for all electrical commodity groups within the scope of this review. The applicant determined that the potential aging effects are based upon materials of construction and their exposure to environmental stressors, such as heat, radiation, and moisture.

The AMR identifies one or more AMPs to be used to demonstrate that the effects of aging will be managed to assure that the intended functions will be maintained consistent with the CLB for the period of extended operation. The programs to be used for managing the effects of aging were compared to those listed in the GALL Report and evaluated for consistency with GALL Report programs that are relied on for license renewal. The results are documented and discussed in Subsection 3.6.2 using the format suggested by the SRP-LR. AMPs are described in Appendix B.

Based on a review of potential aging effects using the Cable AMG, the following stressors and aging effects were identified.

Applicable Stressor	**Voltage Category** [1]	**Applicability**	**Potential Aging Effects**
Heat, oxygen	Low & Medium	All insulation materials	Reduced IR; electrical failure
Radiation, oxygen	Low & Medium	All insulation materials	Reduced IR electrical failure
Moisture and voltage stress	Medium	All insulation materials exposed to standing water	Electrical failure (caused by a breakdown of the insulation)

Notes: 1. Low-voltage (≤1000 volts alternating current (Vac) or ≤250 volts direct current (Vdc)) and medium-voltage (2 kVac—15 kVac)

The applicant's AMRs included an evaluation of site-specific and industry operating experience. The site-specific evaluation included reviews of (1) the Corrective Action Program, (2) licensee event reports, (3) the Maintenance Rule database, and (4) interviews with systems engineers. These reviews concluded that the aging effects requiring management based on RNP operating experience were consistent with aging effects identified in GALL.

The applicant's review of industry operating experience included a review of operating experience published since the effective date of the GALL Report. The results of this review concluded that aging effects requiring management based on industry operating experience were consistent with aging effects identified in GALL.

The applicant's ongoing review of plant-specific and industry-wide operating experience is conducted in accordance with the RNP Corrective Action and Operating Experience Programs.

3.6.2 Staff Evaluation

In Section 3.6 of the LRA, the applicant described its AMR for electrical and I&C systems at RNP. The staff reviewed LRA Section 3.6 to determine whether the applicant has provided sufficient information to demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation, in accordance with the requirements of 10 CFR 54.21(a)(3), for electrical and I&C system components that are determined to be within the scope of license renewal and are subject to an AMR.

The applicant referenced the GALL Report in its AMR. The staff has previously evaluated the adequacy of the aging management of electrical and I&C system components for license renewal as documented in the GALL Report. Thus, the staff did not repeat its review of the matters described in the GALL Report, except to ensure that the material presented in the LRA was applicable, and to verify that the applicant had identified the appropriate programs as described and evaluated in the GALL Report. The staff evaluated those aging management issues recommended for further evaluation in the GALL Report. The staff also reviewed aging management information submitted by the applicant that was different from that in the GALL Report or was not addressed in the GALL Report. Finally, the staff reviewed the UFSAR Supplement to ensure that it provided an adequate description of the programs credited with managing aging for the electrical and I&C system components.

In LRA Section 2.5, the applicant provided a brief description of the electrical and I&C systems and summarized the results of its AMR of the electrical and I&C system components at RNP in LRA Section 3.6.

Table 3.6-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.6 that are addressed in the GALL Report.

Table 3.6-1

Staff Evaluation Table for RNP Electrical Components Evaluated in the GALL Report

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Electrical equipment subject to 10 CFR 50.49 EQ requirements	Degradation due to various aging mechanisms	Environmental qualification of electrical components	B.2.9 (This AMP was not in the original LRA). See RAI 4.4-2.	See Section 4.4

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Electrical cables and connections not subject to 10 CFR 50.49 EQ requirements	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/thermoxidative degradation of organics; radiolysis and photolysis (ultraviolet (UV) sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP for electrical cables and connections not subject to 10 CFR 50.49 EQ requirements	B.4.6	Consistent with GALL. (See Section 3.6.2.1 below)
Electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor IR (high-range radiation monitoring instrumentation circuits)	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/thermoxidative degradation of organics; radiation-induced oxidation; moisture intrusion	AMP for electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements	B.4.7 (This AMP was not in the original LRA). See RAI 3.6.1-2.	Consistent with GALL (see Section 3.6.2.3.2 below)
Electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor IR (neutron flux instrumentation circuits)	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/thermoxidative degradation of organics; radiation-induced oxidation; moisture intrusion	AMP for electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements	B.4.8 (This AMP was not in the original LRA). See RAI 3.6.1-2.	Non-GALL Program (see Section 3.6.2.3.2 below)

Component Group	Aging Effect/Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Inaccessible medium-voltage (2 kV to 15 kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements	Formation of water trees, localized damage leading to electrical failure (breakdown of insulation); water trees caused by moisture intrusion	AMP for inaccessible medium-voltage cables not subject to 10 CFR 50.49 EQ requirements	No AMP Required	(see Section 3.6.2.3.3 below)
Electrical connectors not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage	Corrosion of connector contact surfaces caused by intrusion of borated water	AMP for boric acid corrosion	B.3.2	Consistent with GALL (see Section 3.6.2.3 below)

3.6.2.1 Aging Management Evaluations in the GALL Report That Are Relied On for License Renewal, Which Do Not Require Further Evaluation

For component groups evaluated in GALL for which the applicant has claimed consistency with GALL, and for which GALL does not recommend further evaluation, the staff sampled components in these groups to determine whether the plant-specific components contained in these GALL component groups were bounded by the GALL evaluation. The staff also sampled component groups to determine whether the applicant had properly identified those component groups in GALL that were not applicable to its plant.

On the basis of this review, the staff has determined that the applicant's basis of managing aging effects associated with electrical and I&C system components is consistent with GALL.

3.6.2.2 Electrical Equipment Subject to Environmental Qualification

Environmental qualification is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff reviewed the evaluation of this TLAA separately in Section 4.4 of this SER, following the guidance in Section 4.4 of the SRP-LR.

3.6.2.3 Aging Management Programs for Electrical and Instrumentation and Controls Components

In SER Sections 3.6.2.1, the staff determined that the applicant's AMRs and associated AMPs will adequately manage component aging in electrical and I&C systems. The staff then reviewed specific electrical and I&C system components to ensure that they were properly evaluated in the applicant's AMR.

To perform its review, the staff reviewed the components listed in LRA Table 2.5-1 to determine whether the applicant had properly identified the applicable AMRs and AMPs needed to adequately manage the aging effects of the components. This portion of the staff's review involved identifying the aging effects for each component, ensuring that each aging effect was evaluated using the appropriate AMR in Section 3, and ensuring that management of the aging effect was captured in the appropriate AMP. The results of the staff's review are provided below.

The staff also reviewed the UFSAR Supplements for the AMPs credited with managing aging in electrical and I&C system components to determine whether the program descriptions adequately describe the programs.

The applicant credits five AMPs to manage the aging effects associated with electrical and I&C components. One of the AMPs is credited to manage aging for components in other system groups (common AMP) while the other four AMPs are credited with managing aging only for electrical and I&C components. The staff's evaluation of the common AMP (Boric Acid Corrosion Program), credited with managing aging in electrical and I&C components, is provided in Section 3.0.3.4 of this SER.

The staff's evaluation of the other electrical and I&C components system AMP is provided below.

3.6.2.3.1 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

3.6.2.3.1.1 Summary of Technical Information in the Application

The Non-EQ Insulated Cables and Connections Program is credited for aging management of cables and connections not included in the RNP Environmental Qualification Program. The aging effects/mechanisms of concern are as follows.

- reduced insulation resistance
- electrical failure

The technical basis for selecting a sample of cables to be inspected will be defined prior to the period of extended operation. The sample locations will consider the location of PVC cables inside and outside containment, as well as any known adverse localized environments. (PVC was determined to be the limiting insulation material.)

The Non-EQ Insulated Cables and Connections Program is a new program with no operating experience history. However, as noted in the GALL Report, industry operating experience has shown that adverse localized environments caused by heat or radiation for electrical cables and connections have been shown to exist and have been found to produce degradation of insulating materials that is visually observable.

Upon defining the technical basis for the sample of cables to be inspected under the Non-EQ Insulated Cables and Connections Program, the program will be consistent with GALL XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

The scope of the Non-EQ Insulated Cables and Connections Program will also be applied to instrument cable insulation, as addressed in Section XI.E2 of the GALL Report; however, the calibration of instrument circuits for the purpose of detecting insulation degradation, as called for in GALL XI.E2, is not part of the RNP program. This is acceptable because the visible effects of localized adverse environments caused by heat or radiation would be manifest on all electrical cables, including instrument cables, prior to significant IR degradation.

3.6.2.3.1.2 Staff Evaluation

In Table 3.6-1, the applicant identifies embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR, electrical failure caused by thermal/thermoxidative degradation of organics, radiolysis and photolysis (UV sensitive materials only) of organics, radiation-induced oxidation, and moisture intrusion as the aging effects of cables and connections due to heat or radiation. The staff concurs with the aging effects identified by the applicant. These aging effects are consistent with the aging effects identified by the staff in the GALL Report.

In LRA Section B.4.6, "Non-EQ Insulated Cables and Connections Program," the applicant described its AMP to manage aging in non-EQ insulated cables and connections. The LRA stated that this AMP is consistent with GALL XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" with no deviations. In response to the staff's concern (RAI B.4.6-2) about excluding from the sample, non-PVC cables inside and outside containment in an adverse, localized environment, the applicant, in a letter dated June 13, 2003, stated that the scope of this program includes plant cables and connections of various insulation material types (not just PVC) that may be located in an adverse, localized environment. On the basis of its review, the staff finds that its concern is not resolved. In subsequent discussions with the NRC staff to resolve this issue, the applicant stated that the statement in LRA Section B.4.6, "The sample locations will consider the location of PVC cables inside and outside containment as well as any known adverse localized environments, (PVC was determined to be the limiting insulation material)," will be modified by, "The sample locations will consider the location of cables and connections inside and outside containment as well as any known adverse localized environments." The staff finds that the applicant's resolution of the requested information is acceptable because the sample will consider all insulation material types used inside and outside containment as well as any known adverse localized environments. However, the applicant needs to submit its resolution under oath and affirmation; therefore, this is Confirmatory Item 3.6.2.3.1.2-1. In response to the Confirmatory Item, the applicant, in a letter dated September 16, 2003, revised LRA Section B.4.6 to read, "The sample locations will consider the location of cables and connections inside and outside containment as well as any known adverse localized environments." This is acceptable. On this basis, Confirmatory Item 3.6.2.3.1.2-1 is closed.

<u>Aging Management Program for Non-EQ Insulated Cables and Connections (B.4.6)</u>

As a result of the AMP audit conducted at RNP on May 28 and 29, 2003, the applicant revised AMP B.4.6, "Non-EQ Insulated Cables and Connections," on June 13, 2003. The applicant stated that this is a condition monitoring program designed to provide reasonable assurance that age-related degradation will not inhibit the intended function of insulated cables and connectors within the scope of license renewal during the period of extended operation. The non-EQ insulated cables and connections managed by this program include those used in power, instrumentation, control, and communication applications. The aging effects managed include embrittlement, discoloration, cracking, swelling, or surface contamination leading to reduced IR or electrical failure.

The evaluation of the applicant's AMP for non-EQ insulated cables and connections focused on program elements. To determine whether the applicant's AMP is adequate to manage the effects of aging so that the intended functions will be consistent with the CLB for the period of extended operation, the staff evaluated the following seven elements—(1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, and (7) operating experience. The staff's evaluation of the applicant's corrective action, confirmation process, and administrative controls is provided separately in Section 3.0.4 of the staff's safety evaluation.

Scope of Program: The Non-EQ Insulated Cables and Connections Program includes accessible (i.e., able to be approached and easily viewed) insulated cables and connections installed in structures (i.e., areas) within the scope of license renewal. This program includes cables and connections installed in an adverse, localized environment caused by heat or radiation, as well as other plant areas. An adverse, localized environment is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the cable or connection. Except for the low level signal instrumentation circuits discussed in Section 3.6.2.3.2, the staff concludes that the scope of the program is acceptable because it includes all accessible non-EQ cables and connections that are subject to a potentially adverse, localized environment of heat and radiation that could cause applicable aging effects in these cables and connections.

Preventive Actions: No actions are taken as part of this program to prevent or mitigate aging degradation. This is acceptable because the staff finds no need for such actions.

Parameters Monitored or Inspected: A representative sample of accessible electrical cables and connections installed in adverse, localized environments are visually inspected for cable and connection jacket surface anomalies, such as embrittlement, discoloration, cracking, swelling, or surface contamination. Cable and connection jacket surface anomalies are precursor indications of conductor insulation aging degradation from heat or radiation in the presence of oxygen, and may indicate the existence of an adverse, localized environment. The staff finds the visual technique to be acceptable because it provides indications that can be visually implemented to preclude aging effects of accessible cables and connections.

Detection of Aging Effects: Accessible insulated cables and connections installed in areas within the scope of license renewal will be inspected at least once every 10 years. Following issuance of a renewed operating license for RNP, the initial inspection will be completed before the end of the initial 40-year license term for RNP (July 31, 2010). The staff finds that a 10-year inspection frequency is an adequate period to preclude failure of the conductor insulation because aging degradation is a slow process.

Monitoring and Trending: Trending of discrepancies will be performed as required in accordance with the RNP Corrective Action Program. Corrective action, as described in Chapter 17 of the RNP UFSAR, is implemented by the RNP Quality Assurance Program in accordance with 10 CFR 50, Appendix B. The staff finds the absence of trending to be acceptable because the ability to trend inspection results is limited and the staff did not see a need for such activities. The staff also finds the trending of discrepancies in accordance with the RNP Corrective Action Program to be acceptable.

Acceptance Criteria: The acceptance criterion is no unacceptable, visual indications of jacket surface anomalies which would suggest that conductor insulation applicable aging effects may exist, as determined by engineering evaluation. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the license renewal intended function. The staff finds the acceptance criterion to be acceptable because it ensures that the cables and connections intended functions are maintained under all CLB design conditions for the period of extended operation.

Operating Experience: This is a new program; there is no existing operating experience to validate the effectiveness of this program. The GALL Report is based on industry operating experience through April 2001. Subsequent RNP operating experience will be captured through the operating experience review process. The operating experience review process is fully implemented at RNP and used to improve plant procedures and operating practices. This process will continue throughout the period of extended operation. The staff finds that the applicant has adequately addressed operating experience.

<u>Aging Management Program for Fuse Holders (B.4.9)</u>

In response to the staff's concern about the fuse holder (RAI 2.5.2-1), the applicant stated, in a letter dated April 28, 2003, that fuse holders are typically constructed of blocks of rigid insulating material, such as phenolic resins. Metallic clamps are attached to the blocks to hold each end of the fuse. The clamps can be spring-loaded clips that allow the fuse ferrules or blades to slip in, or they can be bolt lugs to which the fuse ends are bolted. The clamps are typically made of either copper or aluminum. The program focuses on the metallic clamp (clip) portion of the fuse holder. By letter dated June 13, 2003, the applicant clarified that the insulating material for the fuse holders will be managed by the Non-EQ Insulated Cables and Connections Program.

The applicant identified oxidation, corrosion, thermal fatigue from ohmic heating and electrical transients, mechanical fatigue from frequent removal and replacement, or vibration as the principal aging effects for the fuse holder. The staff concurs with the aging effects identified by the applicant. These aging effects are consistent with the aging effects identified by the staff in ISG-05.

RNP has elected to implement an AMP for fuse holders to ensure that they will continue to perform their intended function for the extended period of operation. The program applies to susceptible fuse holders outside of active devices. The program focuses on the metallic clamp (or clip) portion of the fuse holder. The parameters monitored include oxidation, corrosion, chemical contamination, thermal fatigue in the form of high resistance caused by ohmic heating, thermal cycling or electrical transients, and mechanical fatigue caused by frequent manipulation of the fuse itself or vibration. The evaluation of the applicant's AMP for fuse holders focused on program elements. To determine whether the applicant's AMP is adequate to manage the effects of aging so that the intended function will be consistent with the CLB for the period of extended operation, the staff evaluated the following seven elements—(1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, and (7) operating experience. The staff's evaluation of the applicant's corrective action, confirmation process, and administrative controls is provided separately in Section 3.0.4 of the staff's safety evaluation report.

Scope of Program: This program applies to fuse holders located outside of active devices that have been identified as being susceptible to aging effects. Fuse holders inside an active device are not within the scope of this program. The staff considers the scope of the program acceptable.

Preventive Actions: No actions are taken as part of this program to prevent or mitigate aging degradation. This is acceptable because the staff finds no need for such actions.

Parameters Monitored or Inspected: This program will focus on the metallic clamp (or clip) portion of the fuse holder. The parameters monitored include thermal fatigue in the form of high resistance caused by ohmic heating, thermal cycling or electrical transients, mechanical fatigue caused by frequent manipulation of the fuse itself or vibration, chemical contamination, corrosion, and oxidation. The staff finds this acceptable because it provides a means for monitoring the applicable aging effects on the metallic clamp portion of the fuse holder.

Detection of Aging Effects: Identified fuse holders within the scope of license renewal that are located outside of an active device will be tested at least once every 10 years. Testing may include thermography, contact resistance testing, or other appropriate methods to be determined prior to testing. Following issuance of a renewed operating license for RNP, the first test will be completed before the end of the initial 40-year license term for Unit 2 (July 31, 2010). The staff finds the above testing acceptable because these tests will locate hot spots (potential degradation). The staff also finds a 10-year testing frequency is an adequate period to preclude failure of the fuse holders because aging degradation is a slow process.

Monitoring and Trending: Trending of discrepancies will be performed as required in accordance with the Corrective Action Program. Corrective action, as described in Chapter 17 of the Unit 2 UFSAR, is part of the RNP Quality Assurance Program. The staff finds this process to be acceptable because the trending of discrepancies will be performed in accordance with Corrective Action Program.

Acceptance Criteria: The acceptance criteria will be determined based on the test selected for this inspection program. The staff finds this to be acceptable because the acceptance criteria is dependent on the test selected.

Operating Experience: Site-specific and industry-wide operating experience has shown that the loosening of fuse holders is an aging mechanism that, if left unmanaged, has led to a loss of electrical continuity function. The staff finds that the applicant has adequately addressed operating experience.

The staff also reviewed the UFSAR Supplement of the AMPs and finds that it provides an adequate summary description of the program

3.6.2.3.1.3 Conclusions

On the basis of its review of the applicant's Non-EQ Insulated Cables and Connections and fuse holders programs, the staff finds that the programs adequately address the 10 program elements defined in Branch Technical Position (BTS) RLSB-1 in Appendix A.1 of the SRP-LR, and that the programs will adequately manage the aging effects for which they are credited so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 50.21(a)(3). The staff also reviewed the UFSAR Supplement for these AMPs and finds that they provide an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.6.2.3.2 Electrical Cables Used in Instrumentation Circuits Not Subject to 10 CFR 50.49 EQ Requirements That Are Sensitive to Reduction in Conductor Insulation Resistance

3.6.2.3.2.1 Summary of Technical Information in the Application

The applicant stated that the scope of the Non-EQ Insulated Cables and Connections Program will also be applied to instrument cable insulation, as addressed in Section XI.E2 of the GALL Report; however, the calibration of instrument circuits for the purpose of detecting insulation degradation, as called for in GALL XI.E2, is not part of the RNP program. The applicant determined that this is acceptable because the visible effects of localized, adverse environments caused by heat or radiation would be manifest on all electrical cables, including instrument cables, prior to significant IR degradation.

3.6.2.3.2.2 Staff Evaluation

The applicant stated that the GALL Report contains an AMP specifically for cables with sensitive, low-level signals. However, RNP applies the Non-EQ Insulated Cables and Connections Program to this area. The applicant claimed that the inspection required by this program would be effective in identifying visual indications of insulation deterioration caused by environmental conditions (e.g., embrittlement, cracking, melting, discoloration, and swelling). This approach is considered by the applicant to be a preferred alternative to the AMP identified in the GALL Report.

The aging management activity (Table 3.6-1, Item 3, and Table 3.6-2, Item 2 of LRA) submitted by the applicant does not utilize the calibration approach for non-EQ electrical cables used in circuits with sensitive, low-level signals. Instead, these cables are simply combined with all other non-EQ cables under the visual inspection activity. The staff believes, however, that visual inspection alone would not necessarily detect reduced IR levels in cable insulation before the intended function is lost. Exposure of electrical cables to localized environments caused by heat, radiation, or moisture can result in reduced IR. Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in IR is a concern for circuits with sensitive, low-level signals, such as radiation monitoring and nuclear instrumentation, because it may contribute to inaccuracies in the instrument loop.

The staff is not convinced that aging of these cables will initially occur on the outer jacket resulting in sufficient damage to enable visual inspection to be effective in detecting the degradation before IR losses lead to a loss of its intended function, particularly if the cables are also subject to moisture. Therefore, the staff requested the applicant to provide a technical justification that will demonstrate that visual inspection will be effective in detecting damage before current leakage can affect instrument loop accuracy, or propose an alternate aging management activity (RAI 3.6.1-2). In response to the staff's above concern, the applicant, in a letter dated April 28, 2003, stated that RNP will implement AMPs to manage the aging effects of high-range radiation and neutron flux instrumentation circuits. These are two separate, but related programs. The AMP for the high-range radiation monitoring instrumentation circuits is consistent with the Non-EQ Electrical Cables Used in Instrumentation Circuits Program presented in the GALL Report, Volume 2, Section XI.E2. As this cable monitoring program is modeled after the GALL Report, the staff concluded that the requirements of 10 CFR 54.21(a)(3) have been met.

The applicant further stated that neutron flux monitoring instrumentation cables that may experience a reduction in IR require a different program other than the one presented in the GALL Report, Volume 2, Section XI.E2, because these cables are disconnected from their circuits during calibration. The applicant provided the details of the AMP for neutron flux instrumentation circuits. The scope of the program includes those cables associated with the source range, intermediate range, power range, and gamma-metrics circuits of the excore nuclear instrumentation system.

Aging Effects

In Table 3.6-1, the applicant identifies embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR, electrical failure caused by thermal/thermoxidative degradation of organics, radiation-induced oxidation, and moisture intrusion as aging effects of cables and connections due to heat or radiation. The staff concurs with the aging effects identified by the applicant. These aging effects are consistent with the aging effects identified by the staff in the GALL Report.

Aging Management Program

RNP will implement an AMP for high-range radiation monitoring instrumentation circuits. The scope of the program is limited to the cables associated with the containment vessel (CV) high range monitors. The High-Range Radiation Monitoring Instrumentation Circuits Program is consistent with the GALL XI.E2 Program. In this AMP, calibration results or findings of surveillance testing programs are used to identify the potential existence of aging degradation.

Additionally, RNP will implement an AMP for neutron flux instrumentation circuits. The scope of the program is limited to the cables associated with the source range, intermediate range, power range, and gamma-metrics circuits of the excore nuclear instrumentation system. This is a non-GALL program. In this AMP, an appropriate test, such as IR tests, time domain reflectometry (TDR) tests, or I/V testing will be used to identify the potential existence of a reduction in cable IR.

The evaluation of the applicant's AMP focused on program elements. To determine whether the applicant's AMP is adequate to manage the effects of aging so that the intended function will be consistent with the CLB for the period of extended operation, the staff evaluated the following seven elements—(1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, and (7) operating experience. The staff's evaluation of the applicant's corrective action, confirmation process, and administrative controls is provided separately in

Section 3.0.4 of the staff's safety evaluation.

Aging Management Program for Non-EQ Electrical Cables Used in Instrumentation Circuits (B.4.7)

Scope of Program: This program applies to the non-EQ cables used in CV high-range radiation monitoring instrumentation circuits. The staff finds that the scope of the program is acceptable because these cables are part of the calibration program. Cables associated with neutron flux instrumentation circuits are not included in this program because the calibration program does not include these cables.

Preventive Actions: No actions are taken as part of this program to prevent or mitigate aging degradation. This is acceptable because the staff finds no need for such actions.

Parameters Monitored or Inspected: The parameters monitored are determined from the specific calibrations or surveillances performed and are based on the specific instrumentation circuit under surveillance or being calibrated, as documented in plant surveillance calibration or surveillance procedures. The staff finds this approach to be acceptable because it provides a means for monitoring the aging effects of non-EQ electrical cables used in instrumentation circuits.

Detection of Aging Effects: Review of calibration results or findings of surveillance programs can provide an indication of aging effects by monitoring key parameters and providing data based on acceptance criteria related to instrumentation circuit performance. Reviews of results obtained during normal calibrations or surveillances may detect severe aging degradation prior to loss of cable intended function. The first reviews will be completed before the end of the initial 40-year license term for Unit 2 (July 31, 2010) and every 10 years thereafter. All calibrations or surveillances that fail to meet the acceptance criteria will be reviewed at that time. The staff finds this action to be acceptable because the review of calibrations or surveillances that fail to meet the acceptance criteria will provide reasonable assurance that age-related degradation of the cables will be detected prior to loss of cable intended function.

Monitoring and Trending: Trending actions are not included as part of this program because the ability to trend test results is dependent on the specific type of test chosen. Trending of discrepancies will be performed as required in accordance with the RNP Corrective Action Program. Corrective action, as described in Chapter 17 of the Unit 2 UFSAR, is part of the RNP Quality Assurance Program. The staff finds this process to be acceptable because trending of discrepancies will be performed in accordance with the Corrective Action Program.

Acceptance Criteria: Calibration results or findings of surveillances are to be within the acceptance criteria, as set out in the calibration or surveillance procedure. The staff finds this to be acceptable because surveillance or calibration activity ensures that cable intended functions used in instrumentation circuits are maintained under all CLB design conditions during the period of extended operation.

Operating Experience: Changes in instrument calibration data can be caused by degradation of the circuit cable and are a possible indication of potential cable degradation. The staff finds that the applicant did not address the operating experience. In subsequent discussions with the NRC staff to resolve this issue, the applicant stated that this element will be revised to address the operating experience as follows: Industry operating experience indicates that changes in instrument calibration data can be caused by degradation of the circuit cable and are a possible indication of potential cable degradation. This program is for the non-EQ portions of the high range radiation monitoring cabling systems. These cabling systems are located in non-harsh environments and none have experienced age related degradation. The staff finds that the applicant's resolution of the requested information is acceptable because the applicant adequately addressed the operating experience. However, the applicant needs to submit its resolution under oath and affirmation; therefore, this is Confirmatory Item 3.6.2.3.2.2-1. In response to Confirmatory Item 3.6.2.3.2.2-1, the applicant, in a letter dated September 16, 2003, revised the operating experience to include the following statement:

> "Industry operating experience indicates that changes in instrument calibration data can be caused by degradation of the circuit cable and are a possible indication of potential cable degradation. This program is for the non-EQ portions of the high range radiation monitoring cabling systems. These cabling systems are located in non-harsh environments and none have experienced age related degradation."

The staff found this statement to be acceptable. On this basis, Confirmatory Item 3.6.2.3.2.2-1 is closed. The staff also reviewed the UFSAR Supplement of the AMPs and finds that it provides an adequate summary description of the program.

<u>Aging Management Program for Neutron Flux Instrumentation (B.4.8)</u>

Scope of Program: This program applies to the non-EQ cables used in the source range, intermediate range, power range, and gamma-metrics instrumentation circuits of the excore nuclear instrumentation system. The staff finds the scope of the program to be acceptable because these cables are not part of the calibration program.

Preventive Actions: No actions are taken as part of this program to prevent or mitigate aging degradation. This is acceptable because the staff finds no need for such actions.

Parameters Monitored or Inspected: The parameters monitored include a loss of dielectric strength caused by thermal/thermoxidative degradation of organics or radiation-induced oxidation (radiolysis) of organics. The staff finds this to be acceptable because loss of dielectric strength will lead to reduced IR.

Detection of Aging Effects: The cables used in neutron flux instrumentation circuits will be tested at least once every 10 years. Testing may include IR tests, TDR tests, I/V testing, or other testing judged to be effective in determining cable insulation condition. Following issuance of a renewed operating license for RNP, the first test will be completed before the end of the initial 40-year license term for Unit 2 (July 31, 2010). The staff finds the above testing acceptable because such testing will determine cable IR (potential degradation). However, the staff is concerned about the 10-year testing frequency. In subsequent discussions with the NRC staff to resolve this issue, the applicant stated that a review of site operating experience found no age-related failures for neutron monitoring cables or connectors. The only industry operating experience identified for these cables was Westinghouse Technical Bulletin 86-01. This bulletin identified industry concerns with cables used for the source range detector regarding cable degradation due to high operating voltage, radiation, heat, and moisture. Both the source range and intermediate range detector cables inside containment were replaced in 1991 as a result of that bulletin. These cables had operated for 20 years without failure prior to being replaced. The replacement cables were manufactured to Class 1E standards and have remained functional during the last 12 years. The power range cables are the original installed cables and are the same cable type (Amphenol/Essex 21-529) that was originally used in the source range and intermediate range circuits. They have operated for over 32 years without failure, which demonstrates their ability to operate over long periods without a loss of intended function.

In addition, the licensee stated that initial testing of all in-scope neutron monitoring cables will be performed prior to the end of the current license term. This testing will provide a positive means of detecting any significant aging that has occurred since the cables were installed, which in the case of the power range cables will be after 33—40 years of operation. Given the operating experience of these cables and the gradual nature of cable insulation aging, the 10-year testing frequency subsequent to the initial testing provides reasonable assurance that the cables will continue to perform their intended function. The staff finds that the applicant's resolution of the issue is acceptable because the cable insulation degradation is a slow process and RNP operating experience did not identify any cable insulation degradation. Additionally, this 10 year frequency is consistent with NUREG-1801 cable aging management programs frequency. However, the applicant needs to submit its resolution under oath and affirmation; therefore, this is Confirmatory Item 3.6.2.3.2.2-2. In response, the applicant, in a letter dated September 16, 2003, stated the following:

> A review of site operating experience found no age related failures for neutron monitoring cables or connectors. The only industry operating experience identified for these cables was Westinghouse Technical Bulletin 86-01. This Bulletin identified industry concerns with cables used for the source range detector regarding cable degradation due to high operating voltage, radiation, heat, and moisture. Both the source range and intermediate range detector cables inside containment were replaced in 1991 as a result of that bulletin. These cables had operated for 20 years without failure prior to being replaced. The replacement cables were manufactured to Class 1E standards and have remained functional during the last twelve years. The power range cables are the original installed cables and are the same cable type (Amphenol/Essex 21-529) that was originally used in the source range and intermediate range circuits. They have operated for over 32 years without failure, which demonstrates their ability to operate over long periods without a loss of intended function.

In addition, the licensee stated that initial testing of all in-scope neutron monitoring cables will be performed prior to the end of the current license term. This testing will provide a positive means of detecting any significant aging that has occurred since the cables were installed, which in the case of the power range cables will be after 33 - 40 years of operation. Given the operating experience of these cables and the gradual nature of cable insulation aging, the 10-year testing frequency subsequent to the initial testing provides reasonable assurance that the cables will continue to perform their intended function. In addition, the applicant modified the *Operating Experience* element as described below. This is acceptable. On this basis, Confirmatory Item 3.6.2.3.2.2-2 is closed.

Monitoring and Trending: Trending of discrepancies will be performed as required in accordance with the RNP Corrective Action Program. Corrective action, as described in Chapter 17 of the Unit 2 UFSAR, is part of the RNP Quality Assurance Program. The staff finds this to be acceptable because trending of discrepancies will be performed in accordance with the Corrective Action Program.

Acceptance Criteria: The acceptance criteria will be determined based on the test selected for this program. The staff finds this to be acceptable because the acceptance criteria is dependent on the test selected.

Operating Experience: Exposure of electrical cables and connectors to adverse localized environments caused by heat, radiation, or moisture can result in reduced IR. Industry operating experience has shown that the vast majority of failures have occurred near the reactor vessel. This program is for non-EQ neutron monitoring cabling systems. A review of site operating experience found no age-related failures for neutron monitoring cables or connectors. However, Westinghouse Technical Bulletin 86-01 did identify concerns with cables used for the source range detectors regarding cable degradation due to high operating voltage, radiation, heat, and moisture. Both the source range and intermediate range detector cables inside the containment were replaced in 1991 as a result of that technical bulletin. The replacement cables have remained functional during the last twelve years. The power range cables are the original installed cables and are the same cable type (Amphenol/Essex 21-529) that was originally used in the source range and intermediate range circuits. The operating history for these cables demonstrates their reliability and provides reasonable assurance that they will continue to perform their intended function throughout the period of extended operation.

The staff finds that the applicant has adequately addressed operating experience.

The staff also reviewed the UFSAR Supplement of the AMPs and finds that it provides an adequate summary description of the program.

3.6.2.3.2.3 Conclusions

On the basis of its review and audit of the applicant's program, the staff finds that the AMP for high-range radiation monitoring instrumentation is consistent with the GALL XI.E2 program and this program provides adequate management of the aging effects of the cables used in high-range radiation monitoring instrumentation. The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

The staff concludes that the applicant has demonstrated that the AMP for high-range radiation monitoring instrumentation circuits will effectively manage the aging effects of cables used in high-range radiation monitoring instrumentation circuits and that these circuits will perform its intended function in accordance with the CLB, as required by 10 CFR 54.29(a).

On the basis of its review, the staff finds that the AMP for neutron flux instrumentation is a non-GALL program and that this program provides adequate management of the aging effects of the cables used in neutron flux instrumentation. The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program as required by 10 CFR 54.21(d).

The staff concludes that the applicant has demonstrated that the AMP for neutron flux instrumentation circuits will effectively manage the aging effects of cables used in neutron flux instrumentation circuits, and these circuits will perform its intended function in accordance with the CLB, as required by 10 CFR 54.29(a).

3.6.2.3.3 Inaccessible Medium-Voltage Cable Not Subject to 10 CFR 50.49 EQ Requirements

3.6.2.3.3.1 Summary of Technical Information in the Application

The applicant stated that no medium-voltage cables that are potentially susceptible to wetting provide any license renewal intended function. Therefore, no aging management activities are required.

3.6.2.3.3.2 Staff Evaluation

The applicant states that no AMP is required for inaccessible medium-voltage (2 kV to 15 kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements. The applicant determined that no medium-voltage cables, that are potentially susceptible to wetting, provide any license renewal intended function. The staff believes that some circuits (e.g., service water pumps) will be susceptible to wetting and hence an AMP is necessary. The staff requested the applicant, in RAI 3.6.1-4, to identify cables that are installed in conduits or direct buried and explain how the aging due to wetting will be managed. In response to the staff's request, the applicant, in a letter dated April 28, 2003, stated that energized medium-voltage cables are subject to a phenomenon known as water treeing which can ultimately result in failure of the cable insulation. For the purposes of license renewal, medium-voltage is defined as 2 kV to 15 kV. According to the DOE/Sandia Aging Management Guideline (SAND 96-0344), the incidence of cable failure due to water treeing has been found to be more prevalent as voltage level increases. The RNP evaluated all medium-voltage circuits to determine which inscope components were fed by cables that were direct buried, in underground conduits, or in duct banks. This review found that there were no in-scope energized and wetted medium-voltage cables at RNP. This aging mechanism has not been observed in low-voltage cables, which are defined as cables rated at less than 2 kV.

The staff finds that the applicant provided adequate justification for not having an AMP for inaccessible medium-voltage cables not subject to 10 CFR 50.49 EQ requirements.

3.6.2.3.3.3 Conclusions

On the basis of its review, the staff concludes that no AMP is needed to manage the aging of inaccessible medium-voltage cables susceptible to wetting.

3.6.2.4 Aging Management of Plant-Specific Components

The applicant credits one AMP to manage the aging effect associated with plant-specific electrical and I&C components. The following sections provide the results of the staff's evaluation of the adequacy of aging management for plant-specific electrical and I&C components.

3.6.2.4.1 Bus Duct

3.6.2.4.1.1 Summary of Technical Information in the Application

The applicant stated that a bus duct provides a means of connecting electrical power between equipment utilizing a preassembled, metal-enclosed raceway with conductors installed on insulated supports. Bus ducts were not evaluated in the GALL Report. Based on the RNP AMR, no applicable aging effects were identified for the bus duct. Therefore, it is concluded that no aging management activities are required for the extended period of operation.

3.6.2.4.1.2 Staff Evaluation

In the LRA Section 2.5.2, the applicant determined whether bus ducts meet the screening criteria of 10 CFR 54.21(a)(1)(i) and evaluated these components against 10 CFR 54.21(a)(1)(ii). However, in Table 3.6-2, the applicant stated that, "Based on the RNP AMR, no applicable aging effects were identified for the bus duct. Therefore, it is concluded that no aging management activities are required for the extended period of operation." The staff requested the applicant to explain why the connections (two end devices and intermediate points) will not require any aging management (RAI 2.5.2-2). These circuits may be exposed to appreciable ohmic or ambient heating during operation and may experience loosening related to the repeated cycling of connected loads or the ambient temperature environment (described in SAND 96-0344).

In response to the staff's above concern, the applicant, by letter dated April 28, 2003, stated that although the loosening of bolted connections is not a credible aging effect for RNP bus ducts, RNP has conservatively elected to implement an AMP (B.4.10) to identify and manage potential aging degradation.

The applicant stated that the bus ducts utilize preassembled raceway (enclosure) design with internal conductors installed on electrically insulated supports. Bus ducts are constructed of various metals, porcelain, PVC, and silicon caulk. Bus ducts at RNP include (1) generator isolated phase bus ducts, and (2) nonsegregated 4.16 kV and 480 V bus ducts. Bus ducts electrically connect specified sections of an electrical circuit to deliver voltage or current to various equipment and components throughout the plant. In LRA Section 2.5.3.1, the applicant stated that there are no bus ducts within the scope of license renewal that are included in the 10 CFR 50.49 program.

<u>Aging Effects</u>

The applicant identified oxidation, loosening of bolted connections due to thermal cycling, and corrosion due to moisture as the aging effects/mechanism for the bus ducts. The staff concurs with the aging effects identified by the applicant. The staff finds cracks, foreign debris, excessive dust buildup, and evidence of water intrusion as additional aging effects which are addressed in the AMP.

<u>Aging Management Programs (B.4.10)</u>

The applicant stated that although the loosening of bolted connections is not a credible aging effect for RNP bus ducts, RNP has conservatively elected to implement an AMP to identify and manage potential aging degradation. This is a non-GALL program and will provide reasonable assurance that the bus ducts will continue to perform their intended function consistent with the CLB through the period of extended operation.

The evaluation of the applicant's AMP focused on program elements. To determine whether the applicant's AMP is adequate to manage the effects of aging so that the intended function will continue to be performed consistent with CLB for the period of extended operation, the staff evaluated the following seven elements—(1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, and (7) operating experience. The staff's evaluation of the applicant's corrective action, confirmation process, and administrative controls is provided separately in Section 3.0.4 of the staff's safety evaluation.

Scope of Program: This program applies to the iso-phase bus duct, as well as the non-segregated 4.16 kV and 480 V bus ducts within the scope of license renewal. This is acceptable to the staff because the program will include all bus ducts within the scope of license renewal.

Preventive Actions: No actions are taken as part of this program to prevent or mitigate aging degradation. This is acceptable because the staff finds no need for such actions.

Parameters Monitored or Inspected: A sample of accessible bolted connections will be checked for proper torque. This program will also inspect the bus duct for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus itself will be inspected for signs of cracks, corrosion, or discoloration, which may indicate overheating. The internal bus supports will be inspected for structural integrity and signs of cracks. The staff finds that the visual inspection of bus ducts, bus bar, and internal bus supports will provide an indication of aging effects. Additionally, checking of sample bolted connections for proper torque will provide assurance that bus ducts are not exposed to excessive ohmic or ambient heating.

Detection of Aging Effects: This program will be completed before the end of the initial 40-year license term for Unit 2 (July 31, 2010) and every 10 years thereafter. The staff finds that the 10-year inspection frequency is an adequate period to preclude failure of bus ducts because industry experience has shown that the aging degradation is a slow process.

Monitoring and Trending: Trending actions are not included as part of this program. Trending will be performed in accordance with the Corrective Action Program. Corrective action, as described in Chapter 17 of the UFSAR, is part of the RNP Quality Assurance Program. The staff finds this to be acceptable because trending will be performed in accordance with the Corrective Action Program.

Acceptance Criteria: Bolted connections must meet the minimum torque specifications. Additional acceptance criteria include no unacceptable indications of cracks, corrosion, foreign debris, excessive dust buildup, or discoloration, which may indicate overheating or evidence of water intrusion. An "unacceptable indication" is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of license renewal intended function. The staff finds the acceptance criteria to be acceptable because the bolted connections must meet the minimum torque requirement specified by the manufacturer.

Operating Experience: Industry experience has shown that bus ducts exposed to appreciable ohmic or ambient heating during operation may experience loosening of bolted connection related to the repeated cycling of connected loads or the ambient temperature environment. This phenomenon can occur in heavily loaded circuits (i.e., those exposed to appreciable ohmic heating or ambient heating) that are routinely cycled. The staff finds that the proposed program will provide assurance that bus ducts are not exposed to excessive ohmic or ambient heating.

The staff also reviewed the UFSAR Supplement of the AMPs and finds that it provides an adequate summary description of the program.

3.6.2.4.1.3 Conclusions

On the basis of its review of the applicant's program, the staff finds that the program adequately addresses the 10 program elements defined in Branch Technical Position (BTS) RLSB-1 in Appendix A.1 of the SRP-LR, and that the program will adequately manage the aging effects for which it is credited so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 50.21(a)(3). The staff also reviewed the UFSAR Supplement for this AMP and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Therefore, the staff concludes that actions have been identified and have been or will be taken to manage the effects of aging during the period of extended operation on the functionality of SCs subject to an AMR such that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the CLB, as required by 10 CFR 54.29(a).

3.6.2.4.2 Non-EQ Electrical Penetration Assemblies

3.6.2.4.2.1 Summary of Technical Information in the Application

The applicant stated that the components of non-EQ electrical penetration assemblies subject to AMR are the organic insulating materials associated with electrical conductors and connections. Therefore, the non-EQ electrical penetration assemblies are included with the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualifications Requirements Program. Considering cable systems to include penetration assemblies is consistent with GALL XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements in the GALL Report."

3.6.2.4.2.2 Staff Evaluation

In the LRA Section 3.6.2.1, the applicant states that the components of non-EQ electrical penetration assemblies subject to AMR are the organic materials associated with electrical conductors and connections. It is not clear to the staff why the epoxy seal and other insulating material associated with the electrical penetration assemblies do not require an AMR.

In response to the above concern, documented in RAI 3.6.1-1, the applicant, by letter dated April 28, 2003, stated that electrical penetration assemblies are used to pass electrical circuits through the containment wall while maintaining containment integrity. They provide electrical continuity for the circuit, as well as a pressure boundary for the containment. The pressure boundary function of electrical penetration assemblies is addressed in LRA Table 2.4-1. The intent of the electrical AMR of electrical penetration assemblies is to preserve the assemblies' electrical continuity function. The focus of this review is the interaction between the assemblies' organic insulating materials and their operating environment. The organic insulating materials comprise the penetration assemblies' primary insulation system.

In addition to organic insulating materials, there are other materials (metals and inorganic materials) used in the construction of the penetration assembly. These include cable fillers, epoxies, potting compounds, connector pins, plugs, and facial grommets. Consistent with the DOE/Sandia Aging Management Guideline (i.e., SAND 96-0344) these items have no significant effect on the normal aging process of the primary insulation system and do not adversely affect the electrical continuity function. Accordingly, they are not included in the AMR of electrical penetration assemblies. The staff concurred that the components subject to aging in the electrical penetration assemblies are the materials used for the electrical cables and connections.

By letter dated June 13, 2003, the applicant clarified that the electrical penetrations used for high-range radiation monitoring circuits and neutron flux instrumentation circuits are in the EQ Program and, therefore, are not credited to manage the aging effects of non-EQ electrical penetration assemblies. The staff agrees with the applicant that the non-EQ electrical penetration assemblies are included with the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. Section 3.6.2.3.1 provides more detail on this program.

3.6.2.4.2.3 Conclusions

On the basis of its review, the staff concludes that the applicant has adequately identified the aging effect and has an adequate AMP in place for managing the aging effects for containment electrical penetrations, such that the intended functions for the component will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable USAR Supplement program descriptions and concludes that the USAR Supplement provides an adequate program description of the AMPs credited for managing aging in containment electrical penetrations to satisfy 10 CFR 54.21(d)..

3.6.2.4.3 High-Voltage Electrical Switchyard Bus

3.6.2.4.3.1 Summary of Technical Information in the Application

The switchyard bus electrically connects specified sections of an electrical circuit to deliver voltage or current to various equipment and components throughout the plant. The switchyard bus is used in switchyards to connect two or more elements of an electrical power circuit, such as active disconnect switches and passive transmission conductors. The material used for the switchyard bus is aluminum and iron.

<u>Aging Effects</u>

The applicant identified connection surface oxidation and vibration as the aging effects/mechanism for the switchyard bus.

<u>Aging Management Program</u>

The applicant states that connection surface oxidation is an applicable aging effect. All switchyard bus connections have welded and/or compression connections. For the service conditions encountered at RNP, no aging effects have been identified that could cause a loss of intended function. Vibration is not an applicable aging mechanism because the switchyard bus has no connections to moving or vibrating equipment. Switchyard buses are connected to flexible conductors that do not normally vibrate and are supported by insulators mounted to static, structural components, such as cement footings and structural steel. This configuration provides reasonable assurance that the switchyard bus will perform its intended function for the period of extended operation. No AMP for switchyard bus is required.

3.6.2.4.3.2 Staff Evaluation

In Table 1, "AMR Results for the Offsite Power System Electrical Components," of the RAI 2.5.1-1 response, the applicant identified connection surface oxidation and vibration as the aging effects/mechanism for the switchyard bus. The staff concurs with the aging effects identified by the applicant. The staff also finds that the applicant adequately addressed the reasons that these aging effects are not applicable aging effects at RNP. The staff agrees that there is reasonable assurance that the switchyard bus will perform its intended function for the period of extended operation.

3.6.2.4.3.3 Conclusions

On the basis of the staff's review of the information presented in the RAI 2.5.1-1 response, the staff concludes that the switchyard bus has no aging effects that require management.

3.6.2.4.4 High-Voltage Transmission Conductors

3.6.2.4.4.1 Summary of Technical Information in the Application

Transmission conductors are uninsulated, stranded electrical cables used in switchyards, switching stations, and transmission lines to connect two or more elements of an electrical power circuit, such as active disconnect switches, power circuit breakers, and transformers to a passive switchyard bus. Transmission conductors are made of aluminum core steel reinforced (ACSR).

<u>Aging Effects</u>

The licensee identified loss of conductor strength and vibration as the aging effects/mechanism for the transmission conductors.

<u>Aging Management Program</u>

The applicant stated that loss of conductor strength due to corrosion of aluminum core steel reinforced transmission conductors is a very slow process. This process is even slower for rural areas with generally less suspended particles and sulfur dioxide concentrations in the air than urban areas. RNP is located in a rural area where airborne particle concentrations are comparatively low. Consequently, this is not considered a significant contributor to the aging of RNP transmission conductors. Transmission conductor vibration would be caused by wind loading. Wind loading is considered in the initial design and field installation of transmission conductors and high-voltage insulators throughout the CP&L transmission and distribution network. Loss of material (wear) and fatigue that could be caused by transmission conductor vibration or sway are not considered applicable aging effects that warrant aging management.

3.6.2.4.4.2 Staff Evaluation

In Table 1, "Aging Management Review Results for the Offsite Power System Electrical Components," of its RAI 2.5.1-1 response, the applicant identified loss of conductor strength and vibration as the aging effects/mechanism for transmission conductors. The staff concurs with the aging effects identified by the applicant. The staff also finds that the applicant adequately addressed the reasons these aging effects are not applicable at RNP. Additionally, the staff is aware of tests performed by Ontario Hydroelectric which showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion. The National Electric Safety Code requires that tension on installed conductors be a maximum of 60 percent of the ultimate conductor strength. Therefore, the staff concludes that there is reasonable assurance that the transmission conductors will perform their intended function for the period of extended operation.

3.6.2.4.4.3 Conclusions

On the basis of the staff's review of the information presented in the RAI 2.5.1-1 response, the staff concludes that transmission conductors have no aging effects that require management.

3.6.2.4.5 High-Voltage Insulators

3.6.2.4.5.1 Summary of Technical Information in the Application

High-voltage insulators typically used on transmission towers are insulating materials in a form designed to (1) support a conductor physically, and (2) separate the conductor electrically from another conductor or object. High-voltage insulators serve as an intermediate support between a supporting structure (such as a transmission tower or support pedestal) and switchyard bus or transmission conductor. Materials used for the high-voltage insulators are porcelain and metal.

Aging Effects

The applicant identified surface contamination, cracking, and loss of material due to wear as the aging effects/mechanism for the switchyard bus.

Aging Management Program

The applicant stated that surface contamination is not an applicable aging mechanism. The buildup of surface contamination is typically a slow, gradual process. The RNP is located in a rural area where airborne particle concentrations are comparatively low. Consequently, the rate of contamination buildup on the insulators is not significant. Any such contamination accumulation is washed away naturally by rainwater. The glazed surface on high-voltage insulators at RNP aids in the removal of this contamination. Therefore, there are no applicable aging effects that require management. Cracking is not an applicable aging mechanism. Cracking or breaking of porcelain insulators is typically caused by physical damage which is event driven, rather than an age-related mechanism. Mechanical wear is an aging effect for strain and suspension insulators if they are subject to significant movement. RNP transmission conductors do not normally swing, and when they do, because of strong winds, they dampen quickly once the wind has subsided. Loss of material due to wear has not been identified during routine inspections at RNP. No AMP is required.

3.6.2.4.5.2 Staff Evaluation

In Table 1, "Aging Management Review Results for the Offsite Power System Electrical Components," of its RAI 2.5.1-1 response, the applicant identified surface contamination, cracking, and loss of material due to wear as the aging effects/mechanism for high-voltage insulators. The staff concurs with the aging effects identified by the applicant. The staff also finds that the applicant adequately addressed the reasons these aging effects are not applicable at RNP. The staff agrees that there is reasonable assurance that the high-voltage insulators will perform their intended function for the period of extended operation.

3.6.2.4.5.3 Conclusion

On the basis of the staff's review of the information presented as in the RAI 2.5.1-1 response, the staff concludes that high-voltage insulators have no aging effects that require management.

3.6.3 Evaluation Findings

The staff has reviewed the information in Section 3.6 of the LRA and the RAI responses dated April 28, 2003, and June 13, 2003. On the basis of its review, the staff concludes that the applicant has adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the electrical instrumentation and controls, such that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation. The staff also reviewed the applicable UFSAR Supplement program descriptions and concludes that the UFSAR Supplement provides an adequate program description of the AMPs credited for managing aging effects, as required by 10 CFR 54.21(d).

4 TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

This section addresses the identification of time-limited aging analyses (TLAAs). The applicant discusses the TLAAs in license renewal application (LRA) Sections 4.2 through 4.6. The staff's review of the TLAAs can be found in Sections 4.2 through 4.6 of this safety evaluation report (SER).

The TLAAs include certain plant-specific safety analyses that are based on an explicitly assumed 40-year plant life. Pursuant to Title 10 of the *Code of Federal Regulations* (CFR), Part 54.21(c)(1), the applicant for license renewal provides a list of TLAAs, as defined in 10 CFR 54.3.

In addition, pursuant to 10 CFR 54.21(c)(2), an applicant must provide a list of plant-specific exemptions granted under 10 CFR 50.12 that are based on TLAAs. For any such exemptions, the applicant must provide an evaluation that justifies the continuation of the exemptions for the period of extended operation.

4.1.1 Summary of Technical Information in the Application

The applicant evaluated calculations for Robinson Nuclear Plant (RNP) against the six criteria specified in 10 CFR 54.3 to identify the TLAAs. The applicant indicated that calculations that meet the six criteria were identified by searching current licensing basis documents, including technical specifications, the updated final safety analysis report (UFSAR), environmental reports, docketed licensing correspondence, and industry documents such as NUREG-1800, Westinghouse Owner's Group Topical Reports, NUREG-1800, and Nuclear Energy Institute (NEI) 95-10. The applicant listed the following TLAAs in Table 4.1-1 of the LRA:

- reactor vessel neutron embrittlement, including analyses for upper shelf energy, pressurized thermal shock
- metal fatigue, including reactor vessel underclad cracking, reactor internals holddown springs and alignment pins, pressurizer insurge/outsurge, steam generators, pressurizer surge line thermal stratifications, and auxiliary feedwater lines
- environmental equipment qualification
- containment tendon stress relaxation
- containment penetration bellows fatigue
- reactor coolant pump fatigue and Code Case N-481 fracture mechanics analyses
- primary loop leak-before-break analysis
- crane mechanical fatigue

- Boraflex depletion allowance
- containment pile corrosion
- containment concrete temperature cycles

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

4.1.2 Staff Evaluation

In LRA Section 4.1, the applicant identified the TLAAs applicable to RNP and discussed exemptions based on TLAAs. The staff reviewed the information to determine whether the applicant provided information adequate to meet the requirements of 10 CFR 54.21(c)(1) and 10 CFR 54.21(c)(2).

As indicated by the applicant, TLAAs are defined in 10 CFR 54.3 as calculations and analyses that meet the following six criteria.

(1) involve systems, structures, and components within the scope of license renewal, as delineated in section 54.4(a)

(2) consider the effects of aging

(3) involve time-limited assumptions defined by the current operating term, for example, 40 years

(4) were determined to be relevant by the applicant in making a safety determination

(5) involve conclusions, or provide the basis for conclusions, related to the capability of the system, structure, and component to perform its intended functions, as delineated in Section 54.4(b)

(6) are contained or incorporated by reference in the current licensing basis

The applicant listed the TLAAs applicable to RNP in Table 4.1-1 of the LRA. Tables 4.1-2 and 4.1-3 in NUREG-1800 identify potential TLAAs determined from the review of other license renewal applications. In RAI 4.1-1 the staff requested that the applicant discuss two other issues:

(1) whether there are any calculations or analyses at RNP that address the topics listed in Tables 4.1-2 and 4.1-3 of NUREG-1800 and were not included in Table 4.1-1 of the LRA

(2) if they do exist, how these calculations or analyses were evaluated against the TLAA definition provided in 10 CFR 54.3

In its response dated April 28, 2003, to the request for additional information (RAI), the applicant indicated the following topics listed in NUREG-1800 are applicable to pressurized water reactor (PWR) facilities and were not included in Table 4.1-1 of the LRA.

(1) inservice flaw growth analysis of structure stability
(2) metal containment corrosion allowance
(3) high-energy line break analysis based on cumulative usage factor
(4) reactor vessel low temperature overpressure protection analysis
(5) main steam supply lines to the auxiliary feedwater pump
(6) reactor coolant pump flywheel fatigue analysis
(7) reactor vessel internals transient analysis
(8) reactor vessel internals fracture toughness ductility reduction
(9) containment liner plate fatigue analysis

On the basis of a search for RNP-specific TLAAs, the applicant identified calculations or analyses applicable to the reactor vessel (RV) for low temperature overpressure protection (LTOP) analysis (item 4), the main steam supply lines to auxiliary feedwater (AFW) pump (item 5), and the reactor coolant pump (RCP) flywheel fatigue analysis (item 6).

The analysis of the main steam supply lines to the AFW pump (item 5) is addressed in LRA Section 4.3.2. No explicit fatigue analysis of the main steam supply lines to the steam-driven AFW pump has been identified for RNP. Items 4 and 6 were determined not to meet the criterion from 10 CFR 54.3 that the analysis involves time-limited assumptions defined by the current operating term. The RNP LTOP analyses (item 4) have been performed for periods less than the current operating term and are periodically updated. Further discussion on this matter is provided in the applicant's response to RAI 4.2.3-1, Part 2. The RCP flywheel fatigue analysis (item 6) has been performed using an operating life of 60 years.

The supplemental RAI response, submitted by letter June 13, 2003, confirmed that, of the nine potential TLAA categories, only categories 4, 5, and 6 are applicable to RNP. On the basis of the discussion above, the staff finds acceptable the applicant's identification of the TLAAs applicable to RNP.

4.1.3 Conclusions

On the basis of its review, the staff concludes that the applicant has provided an acceptable list of TLAAs as defined in 10 CFR 54.3, as required by 10 CFR 54.21(c)(1), and has confirmed that no 10 CFR 50.12 exemptions have been granted on the basis of a TLAA, as required by 10 CFR 54.21(c)(2).

4.2 Reactor Vessel Neutron Embrittlement

During plant service, neutron irradiation reduces the fracture toughness of ferritic steel in the reactor vessel beltline region of light-water nuclear power reactors. Areas of review to ensure that the reactor vessel has adequate fracture toughness to prevent brittle failure during normal and off-normal operating conditions are (1) upper-shelf energy, (2) pressurized thermal shock for PWRs, (3) heatup and cooldown (P-T limits) curves and LTOP setpoints. The staff has evaluated the adequacy of these TLAAs for the items for the period of extended operation.

4.2.1 Summary of Technical Information in the Application

4.2.1.1 Pressurized Thermal Shock

In Section 4.2.1 of the LRA, the applicant summarized the applicable requirements in 10 CFR 50.61 for determining whether the RNP RV beltline materials will have adequate protection against PTS. The applicant stated that the calculated RT_{PTS} temperatures for RV beltline materials, including axial welds, circumferential welds, and plates, have been demonstrated to remain below the applicable PTS screening criteria throughout the 60-year license renewal period. The applicant stated that the limiting location is circumferential weld 10-273, which has a 60-year RT_{PTS} reference temperature more than 25 °F below the screening criterion (i.e., 60-year RT_{PTS} = 275 °F vs the 300 °F screening criterion for circumferential welds). The applicant stated that the RT_{PTS} values were calculated using the methodology found in 10 CFR 50.61.

The applicant also stated that conservative 60-year RT_{PTS} reference temperatures were also calculated for the RV inlet and outlet nozzles and welds, and that the highest 60-year RT_{PTS} reference temperature for the nozzles was 35 °F below the screening criterion (i.e., 60-year RT_{PTS} = 235 °F vs the 270 °F screening criterion for plates, forgings, and axial welds). The applicant stated that the nozzles and nozzle welds have been shown to meet the PTS criteria for 60 years and have been shown not to be the limiting components, since the beltline materials were closer to the limit. The applicant therefore stated that the inlet and outlet nozzles and welds need not be added to the RV Surveillance Program.

The applicant stated that the analysis associated with PTS has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.2.1.2 Reactor Vessel Upper-Shelf Energy

In Section 4.2.2 of the LRA, the applicant summarizes the applicable requirements for upper-shelf energies (USE) of RV beltline materials, as stated in Section IV.A.1 of 10 CFR Part 50, Appendix G. The applicant stated that the USE values for the RNP RV beltline materials were calculated for a 60-year operating period using methodology from 10 CFR Part 50, Appendix G, and RG 1.99, Revision 2, and the 60-year fluence projections.

The applicant stated that for welds and forgings exposed to end of life (EOL) fluence, the USE screening criterion is 50 ft-lbs minimum. The applicant stated that the projected 60-year USE values for reactor beltline axial and circumferential welds were shown to be above the minimum USE screening criteria. The limiting location is weld 2-273A, with a 60-year USE value of 56 ft-lbs, which is acceptable.

The applicant stated that for RV plate materials, a 42 ft-lbs minimum USE acceptance criterion has been established, based upon WCAP-13587, Revision 1, which demonstrated equivalent margins of safety for RNP vessel plates with USE as low as 42 ft-lbs. The applicant also stated that the 60-year USE values were calculated for RNP vessel plates and that the limiting plate location is plate W 10201-4, with a 60-year USE value of 45 ft-lbs, which is acceptable.

The applicant stated that the nozzle forgings have a 60-year USE value of 53 ft-lbs and that the nozzle welds have a 60-year USE value of 52 ft-lbs, compared with the 50 ft-lbs minimum criterion for welds and forgings from 10 CFR Part 50, Appendix G, which is acceptable.

The applicant stated that the analysis associated with USE has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.2.1.3 Plant Heatup/Cooldown (Pressure/Temperature) Curves/Low-Temperature Overpressure Protection Power-Operated Relief Valve Setpoints

In Section 4.2.3 of the LRA, the applicant considered other analyses impacted by neutron embrittlement, specifically those for establishing the heatup/cooldown curves and LTOP setpoints for the RNP RV. These were determined not to be TLAAs because they are not based upon end-of-license fluence projections. The applicant stated that these analyses are periodically updated as required by regulations based upon fluence projections that bound the current period of operation, but that this period is not necessarily associated with the end of license. The applicant also stated that these analyses are also updated whenever new information is available that would significantly affect the projections, either from the Reactor Vessel Surveillance Program or from other industry sources, and that these analyses do not require updating as a part of the license renewal process since they will be updated when required in accordance with applicable regulations.

4.2.2 Staff Evaluation

Pursuant to 10 CFR 54.21(c), the applicant is required to provide a list of TLAAs as part of the application for the renewal of a license. The applicant stated that the group of TLAAs in Section 4.2 of the LRA deals with the cumulative effect of neutron irradiation on the materials that were used to fabricate the beltline region of the RV and whether neutron irradiation could lead to unacceptable embrittlement (i.e., loss of fracture toughness) in these materials before the end of the extended period of operation for RNP. These TLAAs therefore have direct relation to the structural integrity of the RV during the extended period of operation for RNP. For PWR light-water reactors, including RNP, the staff assesses the impacts of neutron irradiation on the following three parameters related to structural integrity for the RV materials:

(1) the reference temperatures for embrittlement (i.e., RT_{PTS} value) to ensure that the RV beltline materials will be adequately protected against postulated PTS events through the end of the extended period of operation for RNP

(2) the Charpy-V notch USE values for the RV beltline materials to ensure that the materials will have adequate ductility through the end of the extended period of operation for RNP

(3) the P-T limits and LTOP setpoints for the reactor vessel to protect the RNP RV during normal, transient, and pressure-test operating conditions through the end of the extended period of operation for RNP

The staff reviewed the TLAAs identified by the applicant and described in Sections 4.2.1, 4.2.2, and 4.2.3 of the LRA to ensure that the RV beltline materials would have sufficient remaining margins of safety for these parameters, as assessed in compliance with the safety margin/screening criteria requirements for these parameters defined in 10 CFR 50.61, Section

IV.A.1 of 10 CFR Part 50, Appendix G, and Section IV.A.2 of 10 CFR Part 50, Appendix G, respectively. The staff also reviewed these TLAAs to determine if the applicant had demonstrated that the TLAAs for parameters related to structural integrity had been adequately projected to the end of the period of extended operation for RNP, as required by 10 CFR 54.21(c)(1)(ii). The staff evaluates these TLAAs for PTS, USE, and P-T/LTOP limits in Sections 4.2.2.1, 4.2.2.2, and 4.2.2.3 of this SER, respectively.

4.2.2.1 Pressurized Thermal Shock

The requirements for demonstrating that RVs in U.S. PWR light-water reactor facilities will have adequate protection against PTS events are specified in 10 CFR 50.61. The rule establishes PTS screening criteria[1] for RV beltline forging, plate, and weld materials, and requires applicants to calculate a PTS reference temperature (i.e., the RT_{PTS} value) for each beltline material in the reactor vessel. The applicant must also demonstrate that the RT_{PTS} values for the materials will remain below the PTS screening criteria until the end of the license for the facility. The rule also contains the requirements for calculating the RT_{PTS} values for the beltline materials, which are based on the calculation methods contained in RG 1.99, Revision 2 (May 1988). The applicant did not include its end-of-extended-operating-period RT_{PTS} value calculations for the RNP beltline RV materials in its TLAA for PTS; instead, it only summarized the RT_{PTS} values for the limiting shell and nozzle materials in the RNP RV beltline through the expiration of the extended period of operation. The applicant stated that the limiting beltline material in the RNP RV was circumferential Weld 10-273 and that the RT_{PTS} value for this material at the expiration of the extended period of operation is 275 °F, which provides a 25 °F margin of safety when compared to the screening criterion for RV circumferential weld materials (300 °F). The applicant stated that for the RV nozzle materials within the RV beltline region, the RT_{PTS} value for the limiting nozzle material at the expiration of the extended period of operation is 235 °F, which is 35 °F less than the screening criterion for RV base metal and axial weld materials (270 °F).

Pursuant to 10 CFR 54.21(c)(1), the TLAA for PTS must demonstrate that RT_{PTS} values for the beltline materials will remain below the PTS screening criteria until the end of the period of extended operation for RNP. In order to demonstrate compliance with the requirements of both 10 CFR 54.21(c)(1) and 10 CFR 50.61, the staff requested, in RAI 4.2.1-1, that the applicant provide the inputs and results for the end-of-extended-operating-period RT_{PTS} calculations for all RNP beltline shell and nozzle materials and their associated weldments. The applicant provided its response to RAI 4.2.1-1 by letter dated May 15, 2003. In this letter, the applicant attached nonproprietary Class 3 topical report WCAP-15828, Revision 0 (March 2003), which provides the updated PTS assessments for the RNP RV through both the current and extended period of operation.

The staff reviewed the data and information in WCAP-15828, Revision 0, as it relates to the PTS assessment for RNP through the expiration of the extended period of operation for the unit (i.e., 60 years total of licensed life, 50 effective full power years (EFPYs). The staff performed an independent assessment of the PTS data in WCAP-15828, Revision 0, to assess the validity of the 50-EFPY RT_{PTS} calculations for the beltline plate, nozzle forgings, and weld materials in

[1]The PTS screening criteria in 10 CFR 50.61 are 270 °F for RV beltline forgings, plates, and longitudinal (axial) welds and 300 °F for RV beltine circumferential welds.

the RNP reactor vessel. The staff applied the 50 EFPY neutron fluence values cited in the report for the respective beltline materials in the RNP RV. These fluences are based on the material test data from the latest capsule withdrawal for the RNP Reactor Vessel Material Surveillance Program (i.e., Capsule X, as reported in WCAP-15805 March 2002).

The staff's independent calculation of the RT_{PTS} values for the RNP reactor vessel beltline materials through 50 EFPYs of operation confirms that all of the materials will have sufficient protection and margin of safety against PTS events through the expiration of the extended period of operation for the unit. The staff based its RT_{PTS} calculations on the 50-EFPY neutron fluences reported in WCAP-15828 for the RNP beltline materials. For the RNP RV, the limiting beltline material for PTS is upper shell-to-lower shell circumferential weld 10-273 (Weld Heat No. W5214). The staff calculated two RT_{PTS} values for this material—the first RT_{PTS} value as calculated if the chemistry factor (CF) for the material is obtained from the material copper and nickel alloying contents and determined from Table 1 in 10 CFR 50.61, and the second RT_{PTS} value as calculated if the CF is determined from applicable RV material surveillance capsules for this heat of material (i.e., from Capsules T, V, and X data as applicable to Weld Heat No. W5214). A full safety margin is applied to the calculations. The staff calculated the RT_{PTS} values for these materials to be 282 °F if Table 1 in 10 CFR 50.61 is used to calculate the CF, and 295 °F if the surveillance data are used to determine the CF, respectively. The corresponding RT_{PTS} values reported by the applicant in WCAP-15828 were 289 °F and 297 °F, respectively, and are slightly more conservative than those calculated by the staff.

The applicant and the staff calculations were in reasonable agreement with each other, and all values calculated by the applicant and the staff are below the corresponding PTS screening criterion for circumferential welds stated in 10 CFR 50.61. The staff therefore concludes that the applicant has sufficiently resolved the data requested in RAI 4.2.1-1. The staff also concludes that, based on the RT_{PTS} values for the RNP beltline materials, as calculated by both the applicant and the staff, the RNP RV beltline materials will have sufficient protection against PTS through the expiration of the period of extended operation for RNP. Based on this assessment, the staff concludes that the applicant's TLAA for PTS meets the acceptance criterion stated in 10 CFR 54.21(c)(1)(ii) and is acceptable.

4.2.2.2 Reactor Vessel Upper-Shelf Energy

Section IV.A.1 to 10 CFR Part 50, Appendix G, provides the Commission's requirements for demonstrating that reactor vessels in U.S. PWR light-water reactor facilities will have ductility throughout their service lives. The rule requires that the RV beltline materials have USE values in the transverse direction for the base metal and along the weld for the weld material of no less than 75 ft-lb initially, and must maintain USE values throughout the life of the vessel of no less than 50 ft-lb. However, USE values below these criteria may be acceptable if it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that the lower values of USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code. RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," provides an expanded discussion regarding the calculations of USE values and describes two methods for determining USE values for RV beltline materials, depending on whether or not a given RV beltline material is represented in the plant's Reactor Vessel Material Surveillance Program.

The applicant did not include its end-of-extended-operating-period USE value calculations for the RNP beltline RV materials in its TLAA for USE; instead, it summarized the end-of-extended-operating-period USE values only for the shell, weld, and nozzle forging materials in the RNP RV beltline through the expiration of the extended period of operation. The applicant stated that intermediate shell welds 2-273 A, B, and C will have the lowest USE values for all RNP beltline weld materials at the end of the extended operating period and that the USE values for these welds at the expiration of the extended period of operation are 56 ft-lbs. The applicant also stated that RNP RV nozzle forging materials within the RV beltline region have a USE value of 53 ft-lb at the end of the extended period of operation and that the RNP RV nozzle weld materials have a USE value of 52 ft-lb at the end of the extended period of operation. All of these USE values are above the end-of-life USE value screening criterion of 50 ft-lb and therefore meet the applicable USE requirements of 10 CFR Part 50, Appendix G.

The applicant also indicated that the limiting RV beltline materials for USE are beltline plates which have been evaluated using an equivalent margins analysis (EMA) that demonstrates that the plate materials would have equivalent safety margins for USE down to 42 ft-lb, when compared to the safety margin requirements required by Section XI of the ASME Boiler and Pressure Vessel Code. The applicant indicated that this EMA, as applicable through the end of the extended period of operation for RNP, is provided in topical report WCAP-13587, Revision 1.

For LRAs, pursuant to 10 CFR 54.21(c)(1), the TLAA for USE must demonstrate either that USE values for all RNP beltline materials will remain above the 50 ft-lb screening criterion of Section IV.A.1 of 10 CFR Part 50, Appendix G, through to the expiration of the period of extended operation for RNP, or that the beltline materials will have an acceptable margin of safety against ductile failure equivalent to that if the margin of safety is calculated in accordance with Appendix G to Section XI of the ASME Boiler and Pressure Vessel Code. Therefore in RAI 4.2.2-1, Part 1, in order to demonstrate that the EMA in WCAP-13587, Revision 1, would still be bounding and in compliance with both 10 CFR 54.21(c)(1)(i) and Section IV.A.1 of 10 CFR Part 50, Appendix G, the staff requested that the applicant provide its inputs and results for the USE evaluations for all RNP beltline shell and nozzle materials and their associated weldments through the expiration of the extended period of operation for RNP. In RAI 4.2.2-1, Part 2, the staff requested confirmation that the EMA in WCAP-13587, Revision 1, has been submitted for review and approval by the staff.

The applicant provided its response to RAI 4.2.2-1, Parts 1 and 2, by letter dated May 15, 2003. In its response to RAI 4.2.2-1, Part 1, the applicant submitted nonproprietary Class 3 topical report WCAP-15828, Revision 0 (March 2003), which provides the updated USE assessments for RNP reactor vessel through both the current license period and extended period of operation for RNP. In its response to RAI 4.2.2-1, Part 2, the applicant stated that the assessment in WCAP-13587, Revision 1, provided a bounding EMA for Westinghouse Owners Group plants, and confirmed that the generic EMA in WCAP-13587, Revision 1, was reviewed and approved by the staff.

The RNP is a three-loop Westinghouse light-water reactor design. The NRC safety assessment of April 21, 1994, to the Nuclear Management and Resource Council (NUMARC, which is now the NEI) provides the staff's assessment of Westinghouse Electric Company's generic EMAs for two-loop, three-loop, and four-loop Westinghouse light-water reactor designs. In this safety assessment, the staff summarized the results of its independent elastic-plastic fracture mechanics evaluations (i.e., EMAs) for two-loop, three-loop, and four-loop Westinghouse light-water reactor designs. The staff concluded that three-loop Westinghouse light-water reactor designs will have acceptable safety margins against fracture (i.e., on USE) down to a minimum value of 42 ft-lb.

Appendix A of WCAP-15828 provides the applicant's USE analyses for the beltline plate, weld, and nozzle forging materials in the RNP reactor vessel through the expiration of the extended period of operation for the unit. The staff reviewed the USE data and information in Appendix A of WCAP-15828, Revision 0, as it relates to the USE assessment for RNP through the expiration of the extended period of operation for the unit (i.e., 60 years total of licensed life, 50 EFPYs). The staff also performed an independent assessment of the USE data in WCAP-15828, Revision 0, to assess the validity of the 50 EFPY USE calculations for the beltline plate, nozzle forging, and weld materials in the RNP reactor vessel.

The staff's independent calculation of the USE values for the RNP RV beltline materials through 50 EFPYs of operation confirmed that all of the materials will have a sufficient margin of safety against fracture equivalent to that required by Section XI of the ASME Code through the expiration of the extended period of operation for the unit. The staff applied the 50-EFPY neutron fluence values for the beltline materials at the 1/4T location of the vessel, as cited in WCAP-15828, Revision 0. The 1/4T fluences for the beltline materials at EOLE (i.e., through 50 EFPYs) are based on the latest capsule withdrawal from the RNP Reactor Vessel Material Surveillance Program (i.e., on test data from Capsule X, as reported in WCAP-15805 (March 2002)). For the RNP reactor vessel, the limiting beltline material for USE is upper-shell plate W10201-3 (Plate Heat No. B1255-1). The staff calculated the USE value for this material to be 48.6 ft-lb through 50 EFPY of operation. The corresponding USE value reported by the applicant in WCAP-15828, Revision 0, was 48.4 ft-lb, which is in good agreement with the value calculated by the staff. This value is higher than the minimum allowable value (42 ft-lb) cited in the April 21, 1994, safety assessment for three-loop Westinghouse plants and is therefore acceptable. Based on the information provided by the applicant in its responses to RAI 4.2.2-1, Parts 1 and 2, the staff concludes that the applicant has sufficiently addressed the information and data requested by the staff, and RAI 4.2.2-1, Parts 1 and 2, is resolved. The staff also concludes that, based on the 50-EFPY USE values for the RNP beltline materials, as calculated by both the applicant and the staff, the RNP RV beltline materials will have adequate ductility (i.e., sufficient levels of USE) through the expiration of the period of extended operation for RNP. Based on this assessment, the staff concludes that the applicant's TLAA for USE meets the safety margin requirements of 10 CFR Part 50, Appendix G, and the acceptance criterion stated in 10 CFR 54.21(c)(1)(ii) is acceptable.

4.2.2.3 Plant Heatup and Cooldown (Pressure/Temperature) Curves/Low-Temperature Overpressure Protection Power-Operated Relief Valves Setpoints

The P-T limits and LTOP limits for operating reactors are provided to protect the reactor vessels against fracture during transients that can significantly affect the pressure or temperature of the reactor. The P-T and LTOP limits are established by calculations that utilize the materials and fluence data obtained through the unit-specific Reactor Surveillance Capsule Program. Normally, the P-T limits are calculated for several years into the future and remain valid for an established period of time not to exceed the expiration date for the current operating license. For RNP, the current P-T limit curves are valid through 24 EFPYs.

The P-T limit curve requirements and LTOP limit requirements for RNP are currently included within the scope of the limiting conditions for operation for the plant. Pursuant to 10 CFR 50.90, the applicant is required to submit any proposed changes to the P-T limit requirements or LTOP limit requirements to the staff for review pursuant to the license amendment process of 10 CFR 50.90. The applicant used the licensing protocol to conclude that it does not consider the P-T and LTOP limits for RNP to be TLAAs. In RAI 4.2.2.3-1, the staff informed the applicant that, in all previous applications, the P-T limits and LTOP limits for operating light-water reactors have been identified as TLAAs that fall within the scope of 10 CFR 54.3(a). The staff asked the applicant to confirm whether the P-T limits and LTOP limits for RNP are within scope of the definition for TLAAs, as defined in 10 CFR 54.3(a).

The applicant responded to RAI 4.2.2.3-1 by letter dated May 15, 2003. In its response to RAI 4.2.2.3-1, the applicant indicated that it does not consider the P-T limit and LTOP limits for RNP to be TLAAs for the facility because the current curves, which have been approved through 24 EFPY, are not based on time-limited assumptions for the current operating period (40 years of licensed life, 29 EFPYs). Based on this discussion, the staff concludes that the P-T limits and LTOP limits do not fall within the scope of the definition of TLAAs, as given in 10 CFR 54.3(a), because the current P-T limits and LTOP limits are not based on the end of the licensed life for the facility. However, since the current P-T limits and LTOP limits for RNP are included within the scope of the limiting conditions for operations for RNP, the applicant is required to submit new P-T limits and LTOP limits for the facility for staff review and approval prior to expiration of the P-T limit curves and LTOP limits currently approved in the technical specifications. Pursuant to 10 CFR 54.35, this review process will carry over into the period of extended operation for RNP and ensures that the P-T limit curves and LTOP limits for the extended period of operation will be reviewed by the staff for approval, pursuant to the license amendment process. The staff's review of the P-T limit curves and LTOP limits for the period of extended operation, when submitted, will ensure that the operations of the RNP reactor will be done in a manner that ensures the integrity of the reactor coolant system (RCS) during the extended period of operation. Based on this assessment, the staff concludes that the P-T limits and LTOP limits for RNP do not have to be included within the scope of the TLAAs defined under 10 CFR 54.3(a), and RAI 4.2.2.3-1 is resolved.

4.2.3 UFSAR Supplement

Section 54.21(d) of Title 10 of the *Code of Federal Regulations* requires, in part, applicants to provide a summary description of TLAAs for the periods of extended operation for their facilities. Section A.3.2.1 of the LRA provides the applicant's UFSAR Supplement descriptions for the TLAAs for neutron irradiation embrittlement. The applicant provides its UFSAR Supplement descriptions for the TLAAs on PTS and USE in Sections A.3.2.1.1 and A.3.2.1.2 of the LRA, respectively. The staff reviewed the UFSAR Supplement descriptions for the TLAAs on PTS and USE, as given in Sections A.3.2.1.1 and A.3.2.1.2 of the LRA. In RAI 4.2.3-1, Part 1, the staff requested that the applicant amend the UFSAR supplement descriptions for PTS and USE to provide the technical bases why the TLAAs have been demonstrated to be in compliance with the requirements of 10 CFR 54.21(c)(1)(ii). The applicant provided its response to RAI 4.2.3-1, Part 1, by letter dated April 28, 2003. In this response, the applicant stated that the responses to RAIs 4.2.1-1 and 4.2.2-1, Part 1, describe how the TLAAs for PTS and USE are acceptable for the period of extended operation, respectively, and that the analyses for PTS and USE were identified as TLAAs and were described and evaluated in Section A.3.2.1 of the UFSAR Supplement. The applicant clarified that Section A.3.2.1 of the

UFSAR Supplement provides the technical basis for compliance with the requirements of 10 CFR 54.21(c)(1).

The applicant's responses to RAIs 4.2.1-1 and 4.2.2-1, Part 1, which reference WCAP-15828, Revision 0, provide the TLAAs for PTS and USE. In Section 4.2.2.1 of this SER, the staff concluded that the PTS assessment in WCAP-15828, Revision 0, was acceptable and demonstrates that the RV beltline materials would be in compliance with the PTS screening criteria of 10 CFR 50.61 through the expiration of the extended period of operation for RNP.

In Sections 4.2.2.1 and 4.2.2.2 of this SER, the staff concluded that the PTS and USE assessments in WCAP-15828, Revision 0, were acceptable and demonstrates that the RV beltline materials would be in compliance with the PTS screening criteria of 10 CFR 50.61 and the USE acceptance criteria of 10 CFR Part 50, Appendix G, through the expiration of the extended period of operation for RNP. However, the RT_{PTS} and USE values listed for the limiting PTS and USE materials in the RNP reactor vessel are not current with the limiting values for these materials listed in WCAP-15828, Revision 0. The staff requests confirmation that, at the next update of the UFSAR Supplement for RNP, the applicant will update Sections A.3.2.1 and A.3.2.2 of Appendix A to the LRA to reference the applicability of PTS and USE analyses in WCAP-15828, Revision 0, to the 60-year PTS and USE assessments for the RNP RV beltline materials and will update the corresponding UFSAR Supplement summary descriptions to reference the RT_{PTS} and USE values listed in the report for the limiting PTS and USE materials. This is Confirmatory Item 4.2.3-1.

In its response to Confirmatory Item 4.2.3-1 dated September 16, 2003, the applicant stated that it would amend the FSAR Supplement summary descriptions for the TLAAs on PTS and USE, as given in Sections A.3.2.1 and A.3.2.2, respectively, to read as follows:

> A.3.2.1 Reactor Vessel Neutron Embrittlement
>
> A.3.2.1.1 Pressurized Thermal Shock
>
> 10 CFR S5.61 requires the reference temperature (RT_{PTS}) for reactor vessel beltline materials be less than the "PTS screening criteria" at the expiration date of the operating license unless otherwise approved by the NRC. The screening criteria limit the amount that the material reference temperature, RT_{PTS}, may increase following neutron irradiation.
>
> WCAP-15828, Revision 0, provides an evaluation of PTS for RNP that incorporates the results of the surveillance Capsule X evaluation. The calculated RT_{PTS} temperatures for reactor vessel beltline materials, including plates, forgings, axial welds, inlet nozzles, outlet nozzles, and nozzle welds have been demonstrated to remain below the 270 °F PTS screening criterion throughout the 60-year period of extended operation. The limiting location is Circumferential Weld Seam 10-273, which has an RT_{PTS} temperature of 297 °F.
>
> Therefore the TLAA for Pressurized Thermal Shock has been projected to the end of the period of extended operation in ac
>
> A.3.2.1.1 Upper Shelf Energy
>
> 10 CFR Part 50, Appendix G, paragraph IV.A.1, requires that reactor vessel beltline materials have a Charpy upper-shelf energy (USE) of no less than 50ft-lb (68 J) throughout the life of the reactor vessel unless otherwise approved by the NRC.
>
> WCAP-15828, Revision 0, Appendix A, provides an evaluation of USE for the RNP incorporating the results of the surveillance Capsule X evaluation. WCAP-15828, Appendix A, Table A-3, provides predicted end-of-extended-license (50 EFPY) USE values for the beltline region

> materials. The limiting value is for Upper Shell Plate W-10201-3, which has a predicted 60-year USE of 48.4 ft-lbs. This exceeds the applicable 42 ft-lbs minimum requirement from the Equivalent Margins Analysis provided in WCAP-13587, Revision 1, for this material.
>
> Based on the foregoing discussion, the TLAA for reactor pressure vessel USE has been projected to the end of the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

The applicant's amended UFSAR Supplement summary descriptions for the TLAAs on PTS and USE (1) provide a sound basis as to why the TLAA for PTS and USE, as given in Sections A.3.2.1 and A.3.2.2 of the LRA, comply with the requirements in 10 CFR 50.61 for PTS and in 10 CFR Part 50, Appendix G, for USE through the expiration of the extended period of operation for RNP, and (2) provide a reference to the extended period of operation licensing basis documents containing the TLAAs for PTS and USE. Since the UFSAR Supplement summary descriptions demonstrate why the TLAAs are acceptable and reference the applicable licensing basis documents, the staff therefore concludes that the applicant's UFSAR Supplement summary descriptions for the TLAAs on PTS and USE, as given in Sections A.3.2.1 and A.3.2.2 of the LRA, and amended by the applicant's response to Confirmatory Item 4.2.3-1, are acceptable. Confirmatory Item 4.2.3-1 is resolved.

In Section 4.2.2.3, the staff assessed whether P-T limits and LTOP limits for RNP were within the scope of the staff's definition for TLAAs, as given in 10 CFR 54.3(a). In RAI 4.2.3-1, Part 2, the staff requested that the applicant provide its UFSAR Supplement description for the RNP P-T limits and LTOP limits. The staff's issuance of RAI 4.2.3-1 was based on the assumption that the P-T limits and LTOP limits for RNP would fall within the scope of the definition for TLAAs, as promulgated in 10 CFR 54.3(a). In its response to RAI 4.2.3-1, Part 2, the applicant stated that the Robinson LRA did not have to include a UFSAR Supplement summary description for the RNP P-T limits and LTOP limits because they are not within the scope of 10 CFR 54.3(a) for TLAAs. In Section 4.2.2.3 of this SER, the staff provided its basis for concluding that the P-T limits and LTOP limits for RNP were not considered to be within the scope of the staff's definition of TLAAs, as given in 10 CFR 54.3(a). Since the P-T limits and LTOP limits for RNP are not within the scope of the definition for TLAAs, as required in 10 CFR 54.3(a), the staff concludes that the LRA does not need to include a UFSAR Supplement summary description for the plant's P-T limits and LTOP limits, as would otherwise be mandated by the provisions of 10 CFR 54.21(d).

4.2.4 Conclusions

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the RV neutron embrittlement TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR Supplement contains an appropriate summary description of the RV neutron embrittlement TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d). Therefore, the staff concludes that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1).

4.3 Metal Fatigue

A metal component subjected to cyclic loading at loads less than the static design load may fail due to fatigue. Metal fatigue of components may have been evaluated based on an assumed number of transients or cycles for the current operating term. The validity of such metal fatigue analysis is reviewed for the period of extended operation.

4.3.1 Summary of Technical Information in the Application

The applicant discussed the explicit fatigue design requirements for RNP components in Section 4.3.1 of the LRA. Explicit fatigue analyses, in accordance with ASME Boiler and Pressure Vessel (B&PV) Code Section III, Class A (now Class 1) requirements, were performed during the design process for the Class 1 RCS primary system components. Components were subjected to all transients intended to envelop all foreseeable thermal and pressure cycles within a 40-year operating life. Originally, the methodology was applied to the RV, steam generators (SGs), RCPs, and pressurizer. Additional explicit fatigue analyses were performed to address new fatigue issues such as thermal stratification, insurge/outsurge flow in the pressurizer and surge line, RV internals, and thermal cycling of AFW to main feedwater connections.

The applicant tracks the number of design transients with its Fatigue Monitoring Program. The Fatigue Monitoring Program is discussed in Section B.3.19 of the LRA. The applicant indicated that, based on review of the frequency and severity of actual operating transients, it projects that the original 40-year transient set will remain bounding for 60 years of plant operation. Therefore, the applicant concluded that the fatigue analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Section 4.3.1.1 of the LRA describes the applicant's evaluation of the pressurizer surge line. The pressurizer surge line, originally designed to American National Standards Institute (ANSI) B31.1 rules, was reanalyzed by the explicit fatigue method to account for the impact of thermal stratification issues raised in NRC Bulletin 88-11. The hot-leg nozzle was identified as the limiting fatigue location. The applicant indicated that the number of design transients bounds the number of transients expected for 60 years of plant operation. Therefore, the applicant concluded that the surge line stratification analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Section 4.3.1.2 of the LRA describes the applicant's evaluation of pressurizer insurge and outsurge transients. Additional plant-specific analyses were performed to account for insurges and outsurges in the pressurizer and to account for actual plant operation. The plant-specific analyses were performed because the temperature monitoring data indicated that the temperature profile assumed in previous analyses did not bound the observed data. The plant-specific analyses found the limiting location in the pressurizer to be the surge line nozzle. The applicant indicated that the number of design transients bounds the number of transients expected for 60 years of plant operation. Therefore, the applicant concluded that the analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Section 4.3.1.3 of the LRA describes the applicant's evaluation of RV internals. Explicit fatigue analyses were presented in a Westinghouse topical report, WCAP-10322, Revision 1, October 1984, for the reactor internals holddown spring and alignment pins. Since WCAP-10322, Revision 1, has been incorporated by reference, the fatigue analyses for the reactor internals holddown spring and alignment pins were identified as TLAAs. The calculated cumulative utilization factors (CUFs) were 0.073 and 0.008 for the holddown spring and alignment pin, respectively. The applicant indicated that the number of design transients bounds the number of transients expected for 60 years of plant operation. Therefore, the applicant concluded that the analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Section 4.3.1.4 of the LRA describes the applicant's evaluation of the AFW line. The applicant reported a 1972 leakage, attributed to thermal fatigue cracking, at the 4"x16" connection between the auxiliary and main feedwater (AFW to FW) upstream of the B steam generator. The AFW connections were replaced with thermal-sleeved tees designed to ASME Code Section III, Subsection NB requirements (although this piping was designed originally using United States of America Standards (USAS) B31.1 Code). A fatigue analysis performed for the feedwater branch connection reinforcement plate resulted in an acceptable CUF value of less than 1.0 for the 40-year operating life and for the period of license renewal extended operation. The applicant indicated that assuming successful limitation of transient cycles for the 60-year operational period, the fatigue analyses will remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Section 4.3.2 of the LRA describes the applicant's evaluation of components with implicit fatigue design. The applicant stated that most RNP piping, including RCS piping, has been designed to USAS B31.1, "Power Piping Code." The code requires the application of reduction factors to allowable stresses to account for specified cyclic loadings. No explicit fatigue analyses were required. The applicant indicated that the 40-year design transient set has been demonstrated to be conservative for 60 years of operation for the RCS and, consequently, the number of thermal cycles imposed upon the RCS piping systems is not expected to exceed the original design assumptions. Therefore, the applicant concluded that the current design and licensing basis will be maintained throughout the license renewal period.

Auxiliary heat exchangers at RNP were designed in accordance with Westinghouse specifications and ASME Section III, Class C, or ASME Section VIII requirements. Each of the heat exchangers was designed for a specified number and magnitude of transients required by the specification complying with the rules of implicit fatigue design defined in the applicable codes, including ASME Section III, Class C, which are essentially identical to the B31.1 stress range reduction factors. The applicant indicated that any reductions in allowable stress needed for the components to safely withstand the specified thermal transients would have occurred during the original design of these heat exchangers in order to meet the code design requirements. The applicant indicated that the number of pressure and temperature cycles projected for the 60-year license renewal period does not exceed the number of pressure and temperature cycles originally specified and analyzed for 40 years. Therefore, the applicant concluded that the current designs for the specified heat exchangers, including fatigue considerations, remain valid for the 60-year license renewal period.

Section 4.3.3 of the LRA describes the applicant's evaluation of environmentally assisted fatigue (EAF). The applicant indicated that plant-specific environmental fatigue calculations were performed for the high-fatigue locations identified in NUREG/CR-6260 for older vintage Westinghouse plants. For RNP, four of these locations have ASME Section III explicit fatigue analyses, and the remaining three have USAS B31.1 implicit fatigue analyses. EAF relationships developed in NUREG/CR-6583 for carbon and low-alloy steels, and NUREG/CR-5704 for stainless steels, were used. The calculations use the environmental fatigue multiplier (F_{en}) approach. For the locations with an implicit fatigue evaluation, a comparison with the fatigue analyses in NUREG/CR-6260 was performed by comparing RNP plant-specific design attributes with those used in the NUREG/CR-6260 analyses. The F_{en} was computed for each case and was applied to the CUF values obtained from the NUREG/CR-6260 fatigue analysis. All EAF-adjusted CUFs were less than 1.0. For the locations with an ASME Section III fatigue analyses, EAF factors were calculated and applied to the CUFs from the fatigue analyses. The results showed that of the four locations, only the pressurizer surge line was not shown to have an EAF-adjusted CUF value below 1.0.

As part of the EAF-adjusted CUF analysis, the number of load/unload transients was reduced from 29,000 to 19,000 cycles. Since RNP does not operate in daily load-following mode, the number of load/unload transients experienced to date is less than 300, and the 60-year projection is approximately 600. The applicant indicated that a revision will be made to the RNP design transient set in the UFSAR prior to the license renewal period to limit these transients to a maximum of 19,000 cycles.

In addition to the locations specified in NUREG/CR-6260, the applicant performed environmental fatigue calculations for seven RNP pressurizer locations using 19,000 load/unload transients. The results of the analyses indicated that all locations have an EAF-adjusted CUF value of less than 1.0, except for the pressurizer surge nozzle safe end. Therefore, the applicant concluded that both the welds joining the surge line to the RCS hot leg and to the pressurizer surge nozzle are the limiting locations.

The applicant committed to manage the fatigue of surge line components by performing periodic volumetric examinations in accordance with ASME Section XI, Subsections IWB, IWC, and IWD. The frequency of these inspections, at least once every 10-year interval, is specified within the program documents. These inspections are considered adequate to detect the initiation of fatigue cracking prior to propagation into an unstable flaw. If unacceptable indications are identified, further evaluation, repair, or replacement will be performed as required by ASME Section XI. The applicant indicated that this program is adequate to manage thermal fatigue of the surge line and adjacent components during the license renewal period.

4.3.2 Staff Evaluation

4.3.2.1 Explicit Fatigue Analysis (ASME Section III, Class A)

The applicant performed explicit fatigue analyses, in accordance with ASME B&PV Code, Section III, Class 1, requirements, for the RCS primary system components subjected to transients intended to envelop foreseeable thermal and pressure cycles within a 40-year operating life. Originally, this methodology was applied to the RV, SGs, RCPs, and pressurizer. Additional explicit fatigue analyses were performed to address new fatigue issues such as thermal stratification, insurge/outsurge flow on pressurizer and surge lines, RV internals, and thermal cycling of AFW to main FW connections. The staff reviewed the applicant's evaluation of these components for compliance with the provisions of 10 CFR 54.21(c)(1).

The specific design criterion for fatigue analysis of RCS components involves calculating the CUF. The fatigue damage in the component caused by each transient depends on the magnitude of the resulting stresses. The CUF sums the fatigue damage resulting from each transient pair. The design criterion requires that the CUF not exceed 1.0. The applicant indicated that review of the RNP plant operating histories shows that the number of cycles and severity of the transients assumed in the design of these components envelop the expected transients during the period of extended operation.

The applicant used the terms "design transients," "postulated transients," and "selected transients" interchangeably in LRA Section 4.3.1. In RAI 4.3-1, the staff requested clarification as to the differences and specific designation of the category of transients that was used in the design of the RCS components. In its RAI response dated April 28, 2003, the applicant indicated that during the design process, thermal transient and postulated cycles that were used as the design basis for the 40-year life have been referred to as both "design transients" and "postulated transients" and these terms may be used interchangeably. "Selected transients" are those monitored directly in the Fatigue Monitoring Program, and represent design cycles that bound the actual cycles anticipated during the period of extended plant operation. The staff finds the applicant's clarification acceptable.

Section 4.3.1 of the LRA also discusses the adjustments to "cumulative cycle counts." While partial cycle of design transients is defined and used in the ASME B&PV Code, Section III (the Code), the staff requested that the applicant provide additional clarification of this procedure. In RAI 4.3-2, Part 1, the staff requested that the applicant provide the number of design cycles, current operating cycles, and a description of the transients, and for partial cycle transients, the method used to determine the fraction of a full cycle. In its response dated April 28, 2003, the applicant identified the applicable design codes for RNP components and transient descriptions with design and operating cycles in two tables, including applicable notes. For partial cycle transients, the methodology provided in Section 102.3.2 of USAS B31.1, "Power Piping Code," 1967 edition, was used to determine the fraction of a full cycle. The heatup transient was presented as an example to demonstrate how the equivalent full-temperature range cycles were calculated. The staff finds this method acceptable.

In RAI 4.3-2, Part 2, the staff requested that the applicant provide the number of full-range operating cycles estimated for past operation, the method used to estimate the number of cycles for the remaining and extended life, and the basis of developing assumed cycle data on past and present operations. In its response dated April 28, 2003, the applicant stated that, for transients except plant heatups, cooldowns, and reactor trips, cycles are conservatively extrapolated to 60 years based on the actual average number of transients per year to date (through April 2003). For heatup, cooldown, and trip transients, the extrapolation was based on "learning curve effects" and system shakedowns which occurred early in plant life. For these transients, the rate of accumulation was very high during the first 20 years of plant life (3.8 per year for plant heatups and cooldowns and 9.1 per year for reactor trips) but has diminished dramatically down to 1.1 transients per year for each transient in the last 10 years. This reduced rate of accumulation is believed to represent the best estimate of future operation. The staff finds the applicant's method of transient extrapolation for the remaining and extended life reasonable and conservative, and, therefore, acceptable.

In RAI 4.3-2, Part 3 , the staff requested that the applicant describe the proposed mechanism to adjust and track transients included in the LRA for the remaining and extended life of the plant if operational procedures for future operation are modified. The applicant responded by letters dated April 28 and June 13, 2003, that if operating procedures are changed to the extent that the associated fatigue usage could increase beyond that of the most recent fatigue analysis, the affected fatigue analyses would be revised to account for the more severe thermal transients. If the number of allowable cycles to maintain CUF less than 1.0 remains unchanged, then no change would be required to the Fatigue Monitoring Program limits. If the number of allowable cycles had to be reduced to obtain a CUF value less than 1.0, this reduced number of cycles would become the new Fatigue Monitoring Program cycle limit. The reduction of load/unload transient limit from 29,000 to 19,000 cycles to qualify the pressurizer spray nozzle safe end CUF was used as an example of this process applied to the environmental fatigue calculations performed for license renewal. The staff finds the description of transient adjustment and tracking to keep the Fatigue Monitoring Program allowable cycle limits, using the pressurizer spray nozzle as an example, reasonable and acceptable.

In RAI 4.3-2, Part 4, the staff requested that the applicant provide a quantitative comparison of the cycles and severity of the design transients listed in the LRA with the transients monitored by the Fatigue Monitoring Program described in Section B.3.19 of the LRA and identification of any transients listed in the LRA that are not monitored by the Fatigue Monitoring Program and an explanation of why it is not necessary to monitor these transients. In its RAI response dated April 28, 2003, the applicant stated that the transients that are counted are those most severe and likely to result in fatigue cracking of one or more components. Those that are less likely to result in fatigue, due to low contribution to fatigue usage, would not be useful fatigue indicators and need not be counted. They are denoted by "N/C" in the transient description table attached to the response to RAI 4.3-2. For a given component, the influence of any particular transient on the CUF and the magnitude of total CUF determine whether or not that particular event should be counted and tracked. Based on these factors, a review was performed to identify the design cycles from those in the table that have a significant impact on the component fatigue analyses for RNP. First, component locations with individual CUF values of 0.1 or more were identified. Then, the individual transients that contribute to 50 percent or more of the fatigue usage for these locations with a CUF value of 0.1 or more were identified. These are required to be tracked. The loss of load transient and partial loss of flow transient had not been included in the Fatigue Monitoring Program prior to the evaluation but were added to the program because they meet the criteria specified above. Records were reviewed to determine past occurrences, and the counts were updated as required to assure that they are not approaching their design limits. Using these methods, RNP was able to demonstrate that the original 40-year transient set is conservative and bounding for the 60-year operation of the plant. The staff finds the described method of transient monitoring reasonable and acceptable.

4.3.2.1.1 Pressurizer Surge Line Thermal Stratification

The applicant indicated that plant-specific analyses were performed for pressurizer surge line stratification because the temperature monitoring data indicated that the temperature profile assumed in the Westinghouse generic analyses did not bound the observed plant-specific data. In RAI 4.3-3, the staff requested that the applicant (1) provide data or references to justify that the number of transients projected for 60 years of operation is significantly less than that of transients originally postulated for 40 years, (2) justify the projected RNP transient cycles in view of past and future heatup and cooldown methods, and (3) discuss how the TLAA reanalysis will be performed, if the operations during the extended period are different from those assumed in the design assumptions.

The responses to requests 1 and 2 are detailed in the replies to RAI 4.3-2, Part 2, and RAI 4.3-4, respectively. The applicant's response to RAI 4.3.2-2 was discussed in the previous section of the SER. The applicant's response to RAI 4.3-4 is discussed in the next section. Previous transients that exceeded the specified pressurizer heatup and cooldown limits were evaluated, along with several extra cycles to allow for any unanticipated future transients above these limits. RNP has modified the methods for plant heatup and cooldown to mitigate the pressurizer insurge/outsurge transients, and to assure that the existing heatup rate limit of 100 °F/hr and cooldown rate limit of 200 °F/hr are maintained as required by the technical specifications. The method for performing plant heatup and cooldown during the extended operating period will continue to conform to the specified pressurizer heatup and cooldown limits. If a change in operational method were contemplated that might result in exceeding the specified heatup or cooldown rates, the fatigue analyses for the pressurizer and surge line would be evaluated and, if necessary, revised to account for the increased fatigue usage. However, no such change is anticipated. The staff finds the responses provided to RAIs 4.3-2, 4.3-3, and 4.3-4 adequately address transient cycles for 60-year operation and are acceptable.

4.3.2.1.2 Pressurizer Insurge/Outsurge

Pressurizer cooldown limits may be exceeded if a significant temperature difference exists between the pressurizer and the RCS hot leg. The applicant indicated that the cooldown limit had been exceeded in February 1994 and that a detailed evaluation of the transient was performed. RAI 4.3-4 requested the applicant to provide this information and the RNP-specific temperature difference limit during heatup and cooldown.

In its response, the applicant identified technical specification limits of 100 °F/hr for heatups and 200 °F/hr for cooldowns. If a transient exceeds these limits, actions must be taken to evaluate and determine the effects of the out-of-limit condition on the structural integrity of components. The detailed evaluation of the February 1994 out-of-limit transient also included previous occurrences of transients exceeding the technical specifications limits identified through review of plant operating history. The evaluation included identification of past out-of-limit pressurizer transients, development of enveloping transients, determination of stresses in critical locations, and evaluation of these stresses on the structural integrity of the pressurizer. Pressurizer structural integrity was evaluated with respect to nonductile fracture and fatigue requirements. Fracture analysis showed stress intensity factors calculated for a range of assumed flaw depths to remain below the material fracture toughness. The ASME Code fatigue analysis showed that the increase in fatigue usage from these transient events was small.

The analysis of the February 1994 pressurizer out-of-limit transient included other past out-of-limit transients, totaled 16 cooldown and 8 heatup excursions, and included two new enveloping models that were used to bound the fatigue usage. The analysis conservatively calculated the fatigue usage that would result from 40 occurrences of each of the two new transients. The pressurizer surge line was instrumented for one operating cycle to validate the assumptions used in the analysis and to provide detailed transient data for a more accurate analysis. These data determined that moment ranges were larger than previously analyzed. The measured data were used in a structural reanalysis and revised fatigue analysis. The limiting location at the RCS hot-leg nozzle was determined to have a CUF value of 0.96.

In its response to RAI 4.3-6, the applicant confirmed that none of the pressurizer components which have an explicit fatigue analysis has a 40-year or 60-year CUF value that exceeds 1.0

without consideration of environmental effects. Analyzed components include the pressurizer lower head, heater well, spray nozzle, spray nozzle safe end, surge nozzle, surge nozzle safe end, and instrument nozzles. On the basis of the applicant' s responses to the RAIs, the staff finds that the applicant has adequately addressed insurge/outsurge transients.

When environmental fatigue effects were considered, the only component in the pressurizer that was determined to have an EAF-adjusted fatigue value that exceeds 1.0 is the pressurizer surge nozzle safe end (stainless steel) weld to the pressurizer surge line. Fatigue of this component will be managed in the same manner as the adjacent stainless steel pressurizer surge line components, including the surge line piping and RCS hot-leg nozzle. Section 4.3.2.3 of this SER discusses the management of fatigue for the surge line components with EAF-adjusted CUF values over 1.0.

4.3.2.1.3 Reactor Internals Holddown Spring and Alignment Pins

The applicant reported in Section 4.3.1.3 of the LRA that explicit fatigue analyses for the reactor internals holddown spring and alignment pins were presented in a Westinghouse report. The calculated CUFs were 0.073 and 0.008 for the holddown spring and alignment pin, respectively. The Westinghouse report is the stress report on 312 standard reactor core structures. In RAI 4.3-5, the staff requested that the applicant provide justification of the direct applicability of this stress report to the RNP reactor internals holddown spring and alignment pins.

In its April 28, 2003, response, the applicant confirmed that the Westinghouse report is not directly applicable to RNP. The RNP performed an engineering evaluation of materials used for replacement control rod guide tube support pins. This evaluation included references to two Westinghouse documents, which in turn referenced the Westinghouse report in question. Direct reference to the fatigue evaluation in the Westinghouse report was not part of the engineering evaluation, and RNP was not required to establish a TLAA for the RV internals. However, RNP conservatively incorporated the indirect reference to the fatigue evaluation for these components as being within the scope of license renewal. The staff finds the applicant's clarification acceptable. The applicant has also indicated that the number of transients assumed for 40-year design life bounds the number expected for 60 years of operation. On the basis that the number of design transients bounds the number expected for 60 years of plant operation, the staff finds that fatigue of the reactor internals holddown spring and alignment pins has been adequately evaluated for the period of extended operation.

4.3.2.1.4 Auxiliary Feedwater Line Fatigue Analysis

The applicant reported a 1972 leakage, attributed to thermal fatigue cracking, at the 4"x16" connection between the AFW and main FW lines upstream of the B steam generator. Although the piping was originally designed to USAS B31.1 Code, the AFW to main FW connections were replaced with thermal-sleeved tees designed to ASME Code Section III, Subsection NB, requirements. A fatigue analysis, considered to be a TLAA, was performed for the branch connection reinforcement plate. The RNP reported a CUF value of less than 1.0 for the 40-year life and for the period of extended 60-year operation. These connections are considered as nonstandard (ASME) components for which stress intensification factors may not be defined. In RAI 4.3-7, the staff requested the applicant to provide (1) calculated CUF of the six replacement branch connections, (2) confirmation that no other nonstandard components were used or justification of the acceptability for use in safety systems at RNP, and (3) description of the aging management programs (AMPs) that will be used to provide assurance that the CUFs for these connections will not exceed the limit of 1.0 for the period of extended operation.

In its response by letter dated June 13, 2003 (RAI 4.3-7), the applicant stated that there are three 4" to 16" AFW to main FW connections downstream of the motor-driven and the steam-driven AFW pumps. These connections were designed in accordance with USAS B31.1 requirements. Due to detected leakage, the three connections downstream from the motor-driven pumps were replaced with a better design employing a thermal sleeve, also designed to B31.1 requirements.

The three connections downstream from the steam-driven pumps, two of the pad plate reinforcing plate design and one with the saddle reinforcing plate design, were not replaced. In the early 1990s, more rigorous fatigue analyses were performed for each of these two configurations using methodology from ASME Section III, Class 1, rules. The analyses showed that the saddle plate design was inferior to the pad plate design, and a modification was performed to replace the saddle reinforcement plate with a pad-type reinforcing plate. In conjunction with that modification, an ASME Section III fatigue analysis was performed for the pad plate design for the three connections, and this analysis was determined to be a TLAA for license renewal. However, during the license renewal review of this fatigue analysis, an error was discovered in the analysis, and the analysis was revised in 2002 to correct the error. The three connections downstream from the steam-driven pumps could not be qualified for the full 40-year design transient set, so a reduced number of design transients was postulated. This resulted in a CUF value of 0.99 for 40-year life. Based upon projections of actual transients to date, the qualified number of transients is not expected to be reached until approximately year 50. The applicant indicated that the number of transients used in the analysis will be tracked by the Fatigue Monitoring Program. The applicant further indicated that the components will be either reanalyzed or replaced prior to exceeding the number of transients tracked by the Fatigue Monitoring Program. The staff finds that the applicant's proposed options provide acceptable plant-specific approaches to address fatigue of the connections between the auxiliary and main feedwater lines for the period of extended operation in accordance with 10 CFR 54.21(c)(1). However, in accordance with 10 CFR 54.21(d), these options need to be included in the UFSAR Supplement. This was identified as Confirmatory Item 4.3.2-1.

By letter dated September 16, 2003, the applicant provided a modification to UFSAR Supplement Section A.3.2.2.1 which includes the proposed options to address fatigue of the connections between the auxiliary and main feedwater lines for the period of extended operation. The staff finds the modification to UFSAR Supplement Section A.3.2.2.1 acceptable. Confirmatory Item 4.3.2-1 is closed.

In response to Part 3 of the RAI, the applicant performed reviews during the RNP integrated plant assessment (IPA) and found no nonstandard components used in safety systems, based on USAS B31.1 as the design code. This includes each type of AFW/FW connection. ASME Code, Section III, is not the applicable design code, even though portions of it were used as a basis for preparing the fatigue analyses.

Based on the above review of the LRA and the applicant's responses to the RAI provided in the June 13, 2003, letter, the staff finds that the applicant has provided adequate justification to assure the proper fatigue management of the FW/AFW connections for the extended period of operation.

4.3.2.2 Implicit Fatigue Design (ASME Section III, Class C, ANSI B31.1)

ANSI B31.1 requires that a reduction factor be applied to the allowable bending stress range if the number of full range thermal cycles exceeds 7000. The applicant indicated that the number of design transient cycles was found to bound the number of transient cycles expected for 60 years of plant operation. Therefore, the applicant concluded that the analyses of these piping components remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

In RAI 4.3-8, the staff requested that the applicant provide justification of that expectation and assumption that the USAS B31.1 limit of 7000 equivalent full range cycles will not be exceeded during the period of extended operation for the B31.1 piping systems.

In its April 28, 2003, response, the applicant indicated that the 60-year transient projection results apply to both the explicit Class A fatigue analyses and the implicit Class C (and USAS B31.1) analyses. Fatigue Monitoring Program transient data were evaluated to show that the number of transients expected in 60 years is less than the number postulated for 40 years in the original design. In its June 13, 2003, response, the applicant indicated that the primary sampling piping is no longer used for sampling and was not accumulating additional thermal cycles. Therefore, the applicant concluded that the number of thermal cycles for the primary sampling system would not exceed the USAS B31.1 limits during the period of extended operation. The staff finds the applicant's assessment reasonable and acceptable.

The applicant indicated that auxiliary heat exchangers at RNP were designed in accordance with Westinghouse specifications and ASME Section III, Class C, or ASME Section VIII requirements for a specified set of transients required by the specification complying with the rules of implicit fatigue design method defined in the design code using the stress reduction factors described above. The applicant concluded that no further reductions are needed because, as described previously, the number of pressure and temperature cycles projected for the 60-year license renewal period does not exceed the number of cycles originally specified and analyzed for the 40-year life. Therefore, the current designs for the specified heat exchangers, including fatigue considerations, remain valid. In RAI 4.3-8, the staff also requested that the applicant provide the fatigue design method for this case.

The applicant's April 28, 2003, response indicated that there is no requirement to reduce the allowable stress based on cyclic loadings. ASME Section VIII requires that loads not induce a combined maximum primary membrane plus primary bending stress across the thickness exceeding 1.5 times the maximum allowable stress. It is recognized that high localized discontinuity stresses may exist in accordance with these rules. Insofar as practical, design rules have been written to limit such stresses to a safe level consistent with experience. The staff finds this is consistent with the Code and, therefore, acceptable.

4.3.2.3 Environmentally Assisted Fatigue Evaluation

Generic Safety Issue (GSI)-166, "Adequacy of the Fatigue Life of Metal Components," raised concerns regarding the conservatism of the fatigue curves used in the design of the RCS components. Although GSI-166 was resolved for the current 40-year design life of operating components, the staff identified GSI-190, "Fatigue Evaluation of Metal Components for 60-year Plant Life," to address license renewal. The NRC closed GSI-190 in December 1999 with the following conclusions:

> The results of the probabilistic analyses, along with the sensitivity studies performed, the iterations with industry (NEI and EPRI), and the different approaches available to the licensees to manage the effects of aging, lead to the conclusion that no generic regulatory action is required, and that GSI-190 is closed. This conclusion is based primarily on the negligible calculated increases in core damage frequency in going from 40- to 60-year lives. However, the calculations supporting resolution of this issue, which included consideration of environmental effects, and the nature of age-related degradation indicate the potential for an increase in the frequency of pipe leaks as plants continue to operate. Thus, the staff concludes that, consistent with existing requirements in 10 CFR 54.21, licensees should address the effects of coolant environment on component fatigue life as aging management programs are formulated in support of license renewal.

The LRA indicates that the EAF relationship developed later in NUREG/CR-6583 and NUREG/CR-5704 was used in the calculation of the environmental fatigue multiplier (F_{en}). The LRA indicated that the EAF usage factors were less than 1.0 except for the pressurizer surge line. In RAI 4.3-9, the staff requested that the applicant provide the results of the F_{en} and EAF-adjusted CUF calculation for each of the seven component locations listed in NUREG/CR-6260.

The applicant's April 28, 2003, response provided a table which included the F_{en} values and the EAF-adjusted CUFs for the seven component locations listed in NUREG/CR-6260 that are applicable to an older vintage Westinghouse plant. The staff compared the results presented by the applicant with the results presented in NUREG/CR-6260. On the basis of this comparison, the staff finds the applicant's evaluations are reasonable.

The applicant indicated that the EAF-adjusted usage factor for the surge line would exceed 1.0 during the period of extended operation. The applicant further indicated that it would use an AMP to address surge line fatigue during the period of extended operation. The AMP would rely on ASME Section XI inspections. The staff has not endorsed a procedure on a generic basis which allows for ASME Section XI inspections in lieu of meeting the fatigue usage criteria. In RAI 4.3-10, the staff requested that the applicant provide additional clarification regarding aging management of the surge line during the period of extended operation. The applicant's June 13, 2003, response indicated that fatigue of the surge line will be managed using one or more of the following options:

- further refinement of the fatigue analyses to maintain the EAF-adjusted CUF below 1.0
- repair of the affected locations
- replacement of the affected locations
- management of the effects of fatigue through the use of an augmented inservice inspection program that has been reviewed and approved by the NRC

The applicant commits to provide the NRC with the details of the inspection program prior to the period of extended operation if the last option is selected. As indicated by the applicant, the use of an inspection program to manage fatigue will require prior staff review and approval.

The applicant indicated that LRA Section A.3.2.2.2 would be revised to include the applicant's proposed options for managing the surge line fatigue. The staff finds the applicant's proposed options provide acceptable plant-specific approaches to address EAF of the RNP pressurizer surge line for the period of extended operation in accordance with 10 CFR 54.21(c)(1). The staff identified revision of the UFSAR Supplement as Confirmatory Item 4.3.2-2.

By letter dated September 16, 2003, the applicant provided a modification to UFSAR Supplement Section A.3.2.2.1 which includes the proposed options to address fatigue of the surge line for the period of extended operation. The staff finds the modification to UFSAR Supplement Section A.3.2.2.1 acceptable. Confirmatory Item 4.3.2-2 is closed.

4.3.3 Conclusions

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, that, for the metal fatigue TLAA, the effects of aging on the intended functions will be adequately managed for the period of extended operation. Therefore, the staff has concluded that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1).

4.3.4 Reactor Vessel Underclad Cracking

In Section 4.3.4 of the LRA, the applicant provides the TLAA for assuring that postulated underclad cracks in the RNP RV would remain acceptable for service through the expiration of the extended period of operation for RNP, as evaluated in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.3.4.1 Summary of Technical Information in the Application

In the TLAA evaluation of RV underclad cracks, the applicant considers the effect that additional operation cycles during the period of extended operation would have on postulated underclad cracks in the RNP RV. The applicant cites as a reference a fracture mechanics analysis that was completed in 1971 and which concluded that fatigue growth of potential underclad flaws in RV base metal was insignificant over a 40-year operating life.

The applicant states that the underclad cracking analysis has been updated by a Westinghouse topical report, WCAP-15338, which is applicable to the evaluation of underclad cracks in the RNP RV through the end of the extended period of operation. The applicant states that this report has been approved by the staff in a generic safety evaluation for the Westinghouse Electric Company and that this report demonstrates that postulated underclad cracks in the RNP RV will be acceptable through the expiration of the extended period of operation.

4.3.4.2 Staff Evaluation

WCAP-15338 provides Westinghouse Electric's generic evaluation for underclad cracks in Westinghouse-designed RVs. In order to justify operation of Westinghouse-designed light-water reactors through 60 years of operation, the report evaluates the effect of additional operating cycles during the period of extended operation on fatigue-induced growth of detected underclad cracks in the RVs. The report evaluates the effects that the additional operational cycles would have on a bounding 0.295-inch semi-elliptical surface flaw, which is assumed to grow under the influence of transient cycles for a period of 60 years. In a safety evaluation (SE) dated July 15, 2002, the staff concluded that the flaw depths for detected RV underclad cracks, as evaluated in WCAP-15338, would be acceptable for service without repair over 60 years of licensed operation for two-loop, three-loop, and four-loop Westinghouse-designed light-water reactors. In the SE of July 15, 2002, the staff states that applicants for license renewal may reference that WCAP-15338 satisfies the TLAA requirement of 10 CFR 54.21(c)(1), as it relates to the demonstration that RV underclad cracks are acceptable for service over 60 years of operating life for a licensed Westinghouse-design PWR. However, in order to take credit for the evaluation in WCAP-15338, the staff informed applicants for license renewal that they would need to complete the following two action items:

(1) The applicant is to verify that its plant is bounded by the WCAP-15338 report. Specifically, the renewal applicant is to indicate whether the number of design cycles and transients assumed in the WCAP-15338 analysis bounds the number of cycles for 60 years of operation of the applicant's RV.

(2) To satisfy the requirements of 10 CFR 54.21(d), the renewal applicant referencing WCAP-15338 would need to ensure that the UFSAR description for the TLAA appropriately summarizes the TLAA for RV underclad cracks, including a reference to WCAP-15338 as being bounding and applicable to the evaluation of RV underclad cracks at the applicant's Westinghouse-design light-water reactor facility.

In Section 4.3.4 of the LRA, the applicant indicated that it has verified that WCAP-15338 is applicable to the evaluation of RV underclad cracks at RNP. The applicant also indicated that it has verified that (1) the number of design cycles and transients assumed in the WCAP-15338 analysis bounds the number of cycles for 60 years of operation of the RNP RV, and (2) a summary description of the WCAP-15338 analysis has been included in the RNP UFSAR Supplement. The applicant's TLAA for the RNP RV underclad cracks has been performed in accordance with the staff's evaluation and action items on WCAP-15388, which provided the criteria for ensuring that underclad cracks will be adequately managed to meet the requirements of 10 CFR 54.21(c)(1)(i). The staff therefore concludes that the applicant's TLAA for RV underclad cracking is acceptable.

4.3.4.3 Updated Final Safety Analysis Report Supplement

The applicant provides its UFSAR Supplement description for the TLAA on RV underclad cracking in Section A.3.2.2.3 of the LRA. The staff has reviewed the UFSAR Supplement description for the TLAA on RV underclad cracking and has confirmed that the applicant has provided a sufficient summary of this TLAA in Section A.3.2.2.3 of the LRA. The staff confirmed that the applicant appropriately referenced WCAP-15338 as being applicable to the evaluation of underclad cracks at RNP and that the flaw evaluation for RV underclad cracks in WCAP-15338 bounds the evaluation of underclad cracks at RNP. The staff therefore concludes that the UFSAR Supplement description for the applicant's TLAA on RV underclad cracking is acceptable.

4.3.4.4 Conclusions

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis for the RV underclad cracking remains valid until the end of the period of extended operation. The staff also concludes that the UFSAR Supplement contains an appropriate summary description of the TLAA for RV underclad cracking for the period of extended operation, as required by 10 CFR 54.21(d). Therefore, the staff has concluded that the safety margins established and maintained during the current operating term will be maintained throughout the period of extended operation as required by 10 CFR 54.21(c)(1).

4.3.5 Containment Penetration Bellows Fatigue

4.3.5.1 Summary of Technical Information in the Application

The applicant stated that the fatigue of containment components was reviewed to identify potential TLAAs. Fatigue TLAAs were identified for three replacement bellows assemblies used for hot piping penetrations. The fatigue analysis of the three replacement bellows shows that they are designed to withstand 4000 cycles without cracking. The applicant also stated that the original bellows do not have analyses that fit the definitions of TLAAs.

The significant thermal transients that result in flexure of the hot pipe penetration bellows are those that involve a full-range temperature change in the piping system. This includes the plant heatup and cool downcycles. The original 40-year design basis of the plant specifies 200 heatup and cooldown cycles. The applicant indicated, in Section 4.3.1 of the LRA, that the 40-year transient counts remain conservative for 60 years of operation.

The applicant stated that the number of cycles for which the three containment bellows were qualified in the fatigue calculations exceeds the 200 heatup/cooldown cycles applicable to 60 years of operation. These calculations therefore remain valid for the period of extended operation. The applicant concludes that the analyses associated with containment bellows fatigue remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

4.3.5.2 Staff Evaluation

In RAI 4.3-11, the staff requested that the applicant identify the design code to which the containment penetrations are designed and provide a description of the methodology on which the fatigue analysis of the hot penetrations is based. The applicant was also asked to support its conclusion that the bellows can withstand 4000 cycles of operation without fatigue cracking. In response, the applicant stated that the fatigue evaluation of the hot penetrations is limited to the bellows only. According to the design specifications for the bellows, they are designed in accordance with ASME Code Section III, Subsection NC, and bellows performance equations as listed in Section C of the "Standards of the Expansion Joint Manufacturers Association," 5th Edition, 1980, including the 1985 Addenda.

The other components of the containment penetrations at RNP are described in Section 3.8.1.1.6 of the UFSAR. The applicable codes and standards for the design of hot containment penetrations are described in Section 3.8.1.2. This section states that penetrations conform to the applicable sections of USAS N6.2-1965, "Safety Standard for the Design, Fabrication, and Maintenance of Steel Containment Structures for Stationary Nuclear Power Reactors."

In RAI 4.3-12, the staff inquired if the containment penetration bellows are included within the scope of the RNP Fatigue Monitoring Program. The applicant stated that at RNP, the plant heatup and cooldown transients that involve full-temperature changes in the piping systems are controlled and monitored by the RNP Fatigue Monitoring Program. The UFSAR limits these to 200 heatup and cooldown cycles, based on the 40-year design basis of the plant. These are also the cycles that contribute to the fatigue of the containment penetration bellows. The containment penetration bellows are therefore implicitly included within the scope of the RNP Fatigue Monitoring Program. For license renewal, the number of heatup and cooldown cycles to date were analyzed and projected to 60-year plant operation. The projection demonstrated that the present limit of 200 heatup and cooldown cycles is conservative for 60-year operation. Since the bellows were analyzed for 4000 cycles, the bellows will not exceed their design limits during the period of extended operation. The staff finds the applicant's evaluation acceptable.

4.3.5.3 Conclusions

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1), that, for the hot containment penetrations bellows fatigue TLAAs, the analyses remain valid for the period of extended operation. The staff also concludes that Section A.3.2.2.4 of the UFSAR Supplement contains an appropriate summary description of the containment penetrations bellows fatigue TLAA evaluation for the period of extended operation as required by 10 CFR 54.21(d). Therefore the staff has concluded that in accordance with current industry practice, the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1).

4.3.6 Crane Cycle Load Limits

4.3.6.1 Summary of Technical Information in The Application

The applicant states that the load cycle limits for cranes were identified as a potential TLAA and that two following RNP cranes in the scope of license renewal have a TLAA, which requires evaluation for 60 years. These two cranes are the containment polar crane and the spent fuel cask crane.

<u>Containment Polar Crane</u>

The applicant states that the RNP containment polar crane was designed in accordance with "Electric Overhead Crane Institute (EOCI) Specification for Electric Overhead Traveling Cranes," 1961 (EOCI-61), and American Institute of Steel Construction (AISC), "Manual of Steel Construction," 6^{th} Edition. According to the applicant, EOCI-61 did not require a reduction in allowable stresses for fatigue. However, the AISC 6^{th} Edition permitted up to 10,000 complete stress reversals at maximum stress to occur for the life of the structure.

The applicant has provided an analysis to project the current RNP containment polar crane fatigue analysis for 60 years of plant operation. This analysis is summarized below:

> The total number of lift cycles for the Containment Polar Crane is directly dependent on the number of Refueling Outages. The total number of Refueling Outages for 60 years of operation has been established as 40. The total number of upper and mid-range lifts is 110 per outage for a

total of 40 outages, which equates to a 60-year projection of 4,400 lift cycles. This is less than the 10,000 permissible lift cycles and is therefore acceptable.

Spent Fuel Cask Crane

The applicant has provided a similar assessment to demonstrate that the current RNP spent fuel cask crane fatigue analysis is valid for 60 years of plant operation. This analysis is summarized below:

> The number of lift cycles originally projected for 40 years was 2,500. This can be multiplied by a factor of 1.5 to determine the number of cycles for 60-year life. Therefore, number of load cycles projected for 60 years is 3,750. This is less than the 20,000 permissible cycles and is therefore acceptable.

Based on the above information, the applicant concludes that the analyses associated with fatigue of the containment polar crane and the spent fuel cask crane have been projected to the end of the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.3.6.2 Staff Evaluation

The method of review applicable to the crane cyclic load limit TLAA involves (1) reviewing the existing 40-year design basis to determine the number of load cycles considered in the design of each of the cranes in the scope of license renewal and (2) developing 60-year projections for load cycles for each of the cranes in the scope of license renewal and comparing them with the number of design cycles for 40 years.

Section 4.3.6 of the LRA states that the basic allowable stress calculation of the spent fuel cask crane includes dead weight, live load, and impact allowance. In RAI 4.3-13, the staff requested the applicant to discuss the specific requirements on which the impact allowance was based and indicate its magnitude. In its response dated April 28, 2003, and additional clarification provided during a meeting on May 20, 2003, the applicant made the following statement:

> The spent fuel cask handling crane underwent a load rating capacity upgrade during the 1974/75 time frame. The structural upgrade was performed in accordance with CMAA-70. The CMAA-70 specific requirement for impact allowance of the rated capacity is taken as 1/2% of the load per foot per minute of hoisting speed, but not less than 15%, nor more than 50%, of rated load. The spent fuel cask handling crane support structure modifications utilized an impact allowable of 15% of the lift load.

The staff finds the applicant's response reasonable and acceptable because it clarifies the specific requirements on which the impact allowance is based and it meets the Crane Manufacturers Association of America (CMAA)-70 requirements.

Section 4.3.6 of the LRA states that the spent fuel crane is designed for 20,000 to 100,000 load cycles. In RAI 4.3-14, the staff requested the applicant to provide the basis for the upper and lower limits. In its response dated April 28, 2003, the applicant stated the following:

> The load cycle design requirement for the RNP spent fuel crane was based on less than 2500 load cycles over a 40-year period. This equates to a design requirement of less than 3750 load cycles for the 60-year license renewal period. The CMAA-70 crane classification for the RNP spent fuel

> crane is Class A1. Due to its low usage, the spent fuel crane was designed for the lowest range of cycles (20,000 to 100,000).

The applicant further stated that "Class A1 cranes, which are standby Class A cranes, are used for standby service, with infrequent maintenance and long idle periods, i.e., 'low usage.' Additionally, crane specification CMAA-70 code provides an allowable stress range for structural design dependant on its usage (i.e., number of loading cycles)." Based on the above discussion, the staff finds that the applicant has provided an adequate explanation for the upper and lower limits of the load cycles used in the spent fuel crane design.

The applicant also contends that a review of the operational history of the RNP spent fuel crane indicates that the original design requirement was conservative and will not be exceeded for the 40-year period. Therefore, by extrapolation, the requirement for the 60-year period will not be exceeded. The staff concurs with this assessment.

The minimum factor of safety for the spent fuel crane, as discussed in Section 4.3.6 of the LRA, is based on a maximum tensile strength of 58,000 psi for American Society for Testing and Materials (ASTM)-A36 material. In RAI 4.3-15, the staff asked the applicant to verify that no members of the crane have a lower tensile strength and also identify the members with the minimum factors of safety.

In its response dated April 28, 2003, the applicant stated the following:

> The structural load-bearing members for the RNP spent fuel crane have been fabricated in accordance with CMAA-70 from ASTM A-36 steel (tensile strength of 58,000 psi). A minimum factor of safety was provided for structural load bearing members based on a maximum allowable stress. The maximum basic allowable stress for any member under tension or compression is 17,600 psi. The 17,600 psi allowable is the not to be exceeded allowable stress as stated in the CMAA-70 crane specification for members subjected to repeated loading. The factor of safety reported in the LRA was given based on the tensile strength for ASTM A-36.

Based on its review of the applicant's response, as discussed above, the staff finds that the applicant has satisfactorily addressed the concerns related to the minimum factor of safety.

4.3.6.3 Conclusions

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the crane cycle load limit TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR Supplement contains an appropriate summary description of the crane cycle limit TLAA evaluation for the period of extended operation, as reflected in the license condition as required by 10 CFR 54.21(d). Therefore, the staff has concluded that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii).

4.4 Environmental Qualification of Electrical Equipment

The 10 CFR 50.49 Environmental Qualification Program has been identified as a TLAA for the purposes of license renewal. The TLAA of environmental qualification (EQ) components includes all long-lived, passive and active electrical and I&C components and commodities that are located in a harsh environment and are important to safety, including safety-related and Q-list equipment, non-safety-related equipment whose failure could prevent satisfactory accomplishment of any safety-related function, and the necessary post-accident monitoring equipment.

The staff has reviewed Section 4.4, "Environmental Qualification," of the RNP LRA to determine whether the applicant submitted information adequate to meet the requirements of 10 CFR 54.21(c)(1) for evaluating the EQ TLAA. The staff also reviewed Section 4.4.2, "GSI-168, Environmental Qualification of Electrical Components," of the LRA.

On the basis of this review, the staff requested additional information in a letter to the applicant dated February 11, 2003, with a supplement dated February 21, 2003. The applicant responded to this RAI in letters to the staff dated April 28, 2003, and June 13, 2003.

4.4.1 Electrical and I&C Component Environmental Qualification Analyses

4.4.1.1 Summary of Technical Information in the Application

In the LRA, Section 4.4, the applicant describes the TLAA evaluation methodology and how the results from these evaluations were used to demonstrate that (1) the analyses remain valid for the period of extended operation, (2) the analyses have been projected to the end of the period of extended operation, or (3) the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The following is a summary of the methodology used by the applicant to evaluate the EQ TLAAs and the results from this evaluation.

The Environmental Qualification Program at RNP is a centralized plant support program administered by Design Engineering in order to maintain compliance with 10 CFR 50.49. The scope of the Environmental Qualification Program includes the following categories of electrical equipment located in a harsh environment:

- safety-related equipment
- non-safety-related equipment whose failure could adversely affect safety-related equipment
- the necessary post-accident monitoring equipment

The identification of EQ equipment is specified by procedural controls, and a component database is utilized to maintain an EQ equipment master list.

The Environmental Qualification Program includes three main elements—identifying applicable equipment and environmental requirements, establishing the qualification, and maintaining (or preserving) qualification.

Components included in the RNP Environmental Qualification Program have been evaluated to determine if existing environmental qualification aging analyses remain valid for the period of extended operation. Qualification for the license renewal period will be treated the same as for components currently qualified at RNP for 40 years or less. The Environmental Qualification

Program manages component thermal, radiation, and wear cycle aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, environmentally qualified components must be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Aging evaluation for environmentally qualified components that specify a qualification of at least 40 years are considered TLAAs for license renewal.

Age-related service conditions that are applicable to environmentally qualified components (i.e., 60 years of exposure versus 40 years) were evaluated for the period of extended operation to verify that the current EQ analyses are bounding. Temperature and radiation values assumed for service conditions in the EQ analyses are either design operating values or measured values for RNP. The following paragraphs describe the thermal, radiation, and wear cycle aging effects that were evaluated.

Thermal Considerations

The component qualification temperatures were calculated for 60 years using Arrhenius method, as described in Electric Power Research Institute (EPRI) NP-1558, "A Review of Equipment Aging Theory and Technology." If the component qualification temperature bounded the service temperatures throughout the period of extended operation, then no additional evaluation was required.

Radiation Considerations

The RNP Environmental Qualification Program has established bounding radiation dose qualification values for all environmentally qualified components. Typically, these bounding radiation dose values were determined by component vendors through testing. To verify that the bounding radiation values are acceptable for the period of extended operation, integrated dose values were determined and then compared to the bounding values. The total integrated dose (TID) through the period of extended operation is determined by adding the established accident dose to the normal operating dose for the component.

Wear Cycle Aging Considerations

Wear cycle aging is a factor for some equipment within the Environmental Qualification Program. In cases for which wear cycle aging was considered a credible aging mechanism, wear cycles were evaluated through the end of the new license term.

4.4.1.2 Staff Evaluation

The staff reviewed Section 4.4 of the RNP LRA to determine whether the applicant submitted adequate information to meet the requirements of 10 CFR 54.21(c)(1). In addition, the staff met with the applicant to obtain clarifications and to review specific EQ calculations and reviewed the applicant's response to the staff's RAIs.

In response to the staff's concern about the use of measured values in the EQ analyses (RAI 4.4.1-1), the applicant, by letter dated April 28, 2003, stated that the temperature and radiation values used for service conditions in the EQ analyses discussed in LRA Section 4.4.1 are either the design values or are based on measured values. Design values are based on plant design documentation that supports the CLB including the UFSAR, design calculations, and Environmental Qualification Program evaluations. Measured values are actual measured values taken over a period of 1 year or more.

The pressurizer cubicle is the only area in the containment that uses actual measured temperatures, since temperatures in this area routinely exceed the bulk average containment temperature. Components located in the pressurizer cubicle that were found to be qualified for 60 years had sufficient margin to absorb the increases in normal operating temperatures in the pressurizer cubicle. These components included Rockbestos Firewall III cable and Raychem splice material.

Outside containment, the qualified life calculations are based on either the design temperature of 104 °F or actual measured temperatures. Measured temperatures are based on temperature readings taken each shift by operations personnel. There are no defined harsh temperature areas in the Environmental Qualification Program outside of containment. In the one case where measured temperatures are used for EQ, a qualified life of over 60 years resulted. Aging in this case was based on aging performed for PVC insulated cables that were then subjected to a loss-of-coolant-accident (LOCA). For these cables located outside containment, survival of a LOCA is not a requirement, which results in additional conservatism.

Area radiation levels are monitored continuously in various locations in the containment and reactor auxiliary building (RAB). UFSAR Section 11.5 describes the process and effluent radiation monitoring system. Radiation levels in these areas are indicated, recorded, and alarmed in the control room.

Daily operator rounds, radiation monitoring by health physics personnel (surveys of areas in the RAB at least monthly, and in some cases daily or weekly), and maintenance and engineering personnel provide feedback to engineering through the Corrective Action Program when changes to the plant environment or EQ equipment are encountered. Changes in temperature or radiation levels that could adversely affect qualification would be readily identified. RNP plant procedures govern the frequency of surveillances, radiation surveys, and plant walkdowns. The frequencies range from each shift to each outage.

Containment temperature and radiation are logged at least daily, and other EQ areas are subject to operator rounds at least daily while the plant is operating. The temperature and radiation data obtained are representative of the service conditions of EQ equipment, and any change in temperature or radiation that could adversely affect qualification would be readily identified.

Based upon the above information, the staff finds that the applicant has adequately addressed the subject of concern in RAI 4.4.1-1.

In response to the staff's concern regarding the controls used to monitor changes in plant environmental conditions to periodically validate the environmental data used in analyses (RAI 4.4.1-2), the applicant, by letter dated June 13, 2003, provided the following response:

(a) RNP completed a new containment accident analysis in 1999 that resulted in revision of the temperature versus time profile used as a basis for environmental qualification. Also, RNP completed an Appendix K power uprate in 2002 that resulted in an approximate 1.7% increase in power level.

The Appendix K power uprate resulted in no change to temperature values and a minor change to radiation values. Radiation dose was increased by 1.02 times the current value. When this multiplier was applied to the current dose rates in the containment for the remaining period through the end of the new license term, it was found that the change in dose was minimal and well within the 10% margin typically added to environmentally qualified equipment. Environmental qualification packages are undergoing revision at this time and will be updated prior to the end of the current license term (Commitment Number 41).

(b) The qualification basis for the equipment impacted by the aforementioned changes had sufficient conservatism to maintain existing qualification.

(c) Containment temperature and radiation are logged at least daily, and other EQ areas are subject to operator rounds at least daily while the plant is operating. The temperature and radiation data obtained is representative of the service conditions of EQ equipment, and any change in temperature or radiation that could adversely affect qualification would be readily identified.

UFSAR Section 11.5 describes the Process and Effluent Radiation Monitoring System. Radiation levels in these areas are indicated, recorded and alarmed in the control room.

Operator daily rounds, radiation monitoring by Health Physics personnel (surveys of areas in the RAB at least monthly, and in some cases daily or weekly), and Maintenance and Engineering personnel provide feedback to Engineering through the Corrective Action program when changes to the plant environment or EQ equipment are encountered. Changes in temperature or radiation levels that could adversely affect qualification would be readily identified. RNP plant procedures govern the frequency of surveillances, radiation surveys, and plant walkdowns. The frequencies range from each shift to each outage.

Based upon the above information, the staff finds that the applicant has adequately addressed the subject of concern.

In response to the staff's concern regarding TID through the period of extended operation from the 40-year values (RAI 4.4.1-5), the applicant stated by letter dated April 28, 2003, that the RNP EQ Program has established bounding radiation dose qualification values for environmentally qualified components. Typically, these bounding radiation dose values were determined by component vendors through testing. To verify that the bounding radiation values are acceptable for the period of extended operation, integrated dose values were determined and then compared to the bounding values. The TID through the period of extended operation is determined by adding the established accident dose to the normal operating dose for the component. The normal 60-year operating dose was determined by multiplying the normal 40-year dose by 1.5. Based on this information, the staff finds that the applicant has adequately addressed the subject of concern.

On October 23, 2002, representatives of RNP met with the NRC staff to review a sample of EQ calculations. The staff reviewed the following calculations:

- EQDP-1.0, Revision 9, ASCO Solenoid Valves—AQR Report (4.4.1.2)

- EQDP-1.1, Revision 2, ASCO Solenoid Valves
- EQDP-2.0, Revision 6, Limitorque Model SB-3 and SBM-00 MOV Actuators—Inside Containment (4.4.1.4)
- EQDP-2.1, Revision 5, Limitorque MOV Actuators
- EQDP-3.0, Revision 13, Rockbestos Cable—Firewall III (4.4.1.5)
- EQDP-8.1, Revision 6, Westinghouse Motors—Frame 506 UPZ, 509US, and SBDP-RHR, SI Pumps, HVA 6A, 8A, and 8B (4.4.1.11)
- EQDP-9.0, Revision 4, Crouse-Hinds Electrical Penetration Assemblies (4.4.1.13)
- EQDP-15.1, Revision 6, Kerite FR2/FR3 Insulated Multiconductor Cable (4.4.1.27)
- EQDP-18.1, Revision 2, Westinghouse CET/CCM—Reference Junction Boxes and Potting Adaptors (4.4.1.32)
- EQDP-19.1, Revision 4, Gamma—Metrics Excore Neutron Detectors (4.4.1.34)
- EQDP-31.0, Revision 6, Cable—PVC and XLPE Outside Containment (4.4.1.43)
- EQDP-33.0, Revision 4, Grease—Motors and MOVs (4.4.1.44)
- EQDP-12.1, Revision 2, Raychem Splices—NPKV Stub Kits (4.4.1.19)
- EQDP-34.0, Revision 6, Target Rock Solenoid Valves (4.4.1.45)

The staff verified that the applicant is using standard, approved EQ methodologies and acceptance criteria applicable to EQ as defined by NRC Bulletin 79-01B (the Division of Operating Reactors guidelines), including Supplements 1, 2, and 3; NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," Revision 1; 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"; RG 1.89, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants," Revision 1; various NRC generic letters and information notices; and NRC safety evaluation reports on EQ.

The staff found that all EQ calculations were done using design temperature or measured temperature. The measured temperatures at pressurizer cubicles are higher than the design temperature. These higher temperature values are used for equipment in that area. The staff found that activation energies have not been changed and ohmic heating for power cables was properly considered. A 32 °C rise due to ohmic heating over 40 °C ambient was used for power cables. Wear cycle aging for motors, limit switches, solenoid valves, and multipin connectors was not addressed. By letter dated April 28, 2003, the applicant provided a response to the staff's concerns (RAI 4.4.1-3). On the basis of its review, the staff concludes that the applicant has adequately addressed these concerns.

<u>TLAA Demonstration for Option 10 CFR 54.21(c)(1)(ii)</u>

For the following list of electrical equipment identified in Section 4.4.1 of the LRA, the applicant cites 10 CFR 54.21(c)(1)(ii) in its TLAA evaluation to demonstrate that the analyses have been projected to the end of the period of extended operation:

- 4.4.1.1 ASCO NP8316 and NP8321 Series Solenoid Valves
- 4.4.1.2 ASCO Solenoid Valves—AQR Report
- 4.4.1.4 Limitorque Model SB-3 and SBM-00 Motor-Operated Valve (MOV) Actuators—Inside Containment
- 4.4.1.5 Rockbestos Cable—Firewall III
- 4.4.1.6 Rockbestos RSS-6-104/LE Series Coaxial Cable
- 4.4.1.7 Rockbestos Cable—Firezone R
- 4.4.1.8 GEMS Liquid Level Transmitters—Model XM-54853 and XM-54854
- 4.4.1.9 B&W Valve Monitoring System
- 4.4.1.10 Westinghouse Reactor Containment Fan Cooler (RCFC) Motors
- 4.4.1.11 Westinghouse Motors—Frame 506UPZ, 506US, and SBDP-RHR, SI Pumps, HVA 6A, 6B, 8A, and 8B
- 4.4.1.12 Westinghouse Motors—Model S068C20085—Containment Spray Pumps
- 4.4.1.13 Crouse-Hinds Electrical Penetration Assemblies
- 4.4.1.14 Continental Shielded Instrument Cable—CC2115
- 4.4.1.15 Continental/Anaconda Cable—Instrumentation
- 4.4.1.16 Samuel Moore Dekoron Instrumentation Cables (EPDM and XLPO Insulations)
- 4.4.1.17 Eaton Corporation Dekoron Cable 16 AWG
- 4.4.1.18 Raychem WCSF-N Splices
- 4.4.1.19 Raychem Splices—NPKV Stub Kits
- 4.4.1.20 Raychem Splices—NPK Connection Kits
- 4.4.1.21 Raychem Splices—NMCK Connection Kits
- 4.4.1.22 Raychem Splices—NESK End Seal Kits

- 4.4.1.23 AMP Butt Splices
- 4.4.1.24 AMP PIDG Terminals
- 4.4.1.25 CM-303 Tape Splices Assemblies—Scotch 27 and Scotch 70
- 4.4.1.26 Kerite HTK Power Cable
- 4.4.1.27 Kerite FR2/FR3 Insulated Multiconductor Cable
- 4.4.1.28 Thomas and Betts STA-KON Terminal
- 4.4.1.29 Conax Electrical Conductor Seal Assemblies—ECSA
- 4.4.1.30 Conax Electrical Penetration Assemblies
- 4.4.1.31 Westinghouse CET/CCM—Incore T/C Connectors and MI Cable Assemblies
- 4.4.1.32 Westinghouse CET/CCM—Reference Junction Boxes and Potting Adaptors
- 4.4.1.33 Westinghouse CET/CCM—Intermediate Disconnect Box Connectors
- 4.4.1.34 Gamma—Metrics Excore Neutron Detectors
- 4.4.1.35 Pyco Resistance Temperature Detectors
- 4.4.1.36 Buchanan Terminal Blocks
- 4.4.1.37 Barton Pressure Switches—Model 580A
- 4.4.1.38 NAMCO Receptacle and Connector/Cable Assemblies—Model EC210
- 4.4.1.39 Victoreen High Range Radiation Detectors
- 4.4.1.40 Brand Rex Cable—Instrumentation
- 4.4.1.41 Brand Rex Cable—Control
- 4.4.1.42 Raychem Cable—Flamtrol
- 4.4.1.43 Cable—PVC and XLPE Outside Containment
- 4.4.1.44 Greases—Motors and MOVs
- 4.4.1.45 Target Rock Solenoid Valves
- 4.4.1.46 Boston Insulated Wire—Cable
- 4.4.1.47 Honeywell Model V4-21 Microswitch Assembly

• 4.4.1.48 RAM-Q Connectors

TLAA Demonstration for Option 10 CFR 54.21(c)(1)(iii)

For the list of electrical equipment identified in Section 4.4.1 of the LRA, the applicant cites 10 CFR 54.21(c)(1)(iii) in its TLAA evaluation to demonstrate that the aging effects of the EQ equipment identified in this TLAA will be managed during the extended period of operation by the Environmental Qualification Program activities described in Section B.4.1 of the LRA.

4.4.1.3 Limitorque SBM Motor-Operated Valve Actuators—Outside Containment

In LRA Section 4.4, the applicant stated that the Environmental Qualification Program manages component thermal, radiation, and wear cycle aging through the use of aging evaluation based on 10 CFR 50.49(f) qualification methods. Appendix B, "Aging Management Programs," did not include the Environmental Qualification Program as one of the existing programs. This program will be credited to manage the aging of EQ components. In response to this staff concern (RAI 4.4-2), the applicant, by letter dated April 28, 2003, stated that new Section B.2.9, "Environmental Qualification (EQ) of Electrical Components," should be added to Appendix B. The applicant provided the details of the program.

The staff reviewed the EQ Program to determine whether it will assure that the electrical/I&C components covered under this program will continue to perform their intended function consistent with the CLB for the period of extended operation. The staff's evaluation of the component qualification focused on how the program manages the aging effect through effective incorporation of seven elements—scope of program, preventive action, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, and operating experience. The staff's evaluation of the applicant's corrective actions, confirmation process, and administrative controls is provided separately in Section 3.0.4 of the SER.

Scope of Program—The RNP Environmental Qualification Program includes certain electrical components that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49. The staff considers the scope of the program to be acceptable.

Preventive Actions—Actions that prevent aging effects are not requried by 10 CFR 50.49. The RNP Environmental Qualification Program actions that could be viewed as preventive actions include (1) establishing the component service condition tolerance and aging limits (for example, qualified life or condition limit), (2) refurbishment, replacement, or requalification of installed equipment prior to reaching these aging limits, and (3) where applicable, requiring specific installation, inspection, monitoring, or periodic maintenance actions to maintain equipment aging effects within the qualification. The staff considers these actions acceptable because 10 CFR 50.49 does not require actions that prevent aging effects.

Parameter Monitored or Inspected—EQ component aging limits are not typically based on condition or performance monitoring. However, per RG 1.89 Revision 1, such a monitoring program is an acceptable basis to modify aging limits. Monitoring or inspection of certain environmental, condition, or equipment parameters may be used to ensure that the equipment is within its qualification or as a means to modify qualification. The staff considers this monitoring appropriate because the program objective is to ensure that the qualified life of devices established is not exceeded.

Detection of Aging Effects—The detection of aging effects for inservice components is not required by 10 CFR 50.49. Monitoring of aging effects may be used as a means to modify component aging limits. The staff considers the applicant's program to use the monitoring of aging effects as a means to modify component aging limits acceptable.

Monitoring and Trending—Monitoring and trending of component condition or performance parameters of inservice components to manage the effects of aging are not required by 10 CFR 50.49. Environmental Qualification Program actions that could be viewed as monitoring include monitoring how long qualified components have been installed. Monitoring or inspection of certain environmental, condition, or component parameters may be used to ensure that a component is within its qualification or as a means to modify the qualification. The staff considers this acceptable since 10 CFR 50.49 does not require monitoring and trending of component condition or performance parameters of inservice components to manage the effects of aging.

Acceptance Criteria—The acceptance criteria in 10 CFR 50.49 are that an inservice EQ component is maintained within its qualification including (1) its established aging limits and (2) continued qualification for the projected accident conditions. Compliance with 10 CFR 50.49 requires refurbishment, replacement, or requalification prior to exceeding the aging limits of each installed device. When monitoring is used to modify a component aging limit, plant-specific acceptance criteria are established based on applicable 10 CFR 50.49(f) qualification methods. The staff considers this acceptable since it is consistent with 10 CFR 50.49 requirements of refurbishment, replacement, or requalification prior to exceeding the qualified life of each installed device.

Operating Experience—The RNP Environmental Qualification Program includes consideration of operating experience to modify qualification bases and conclusions, including aging limits. Compliance with 10 CFR 50.49 provides evidence that the component will perform its intended functions during accident conditions after experiencing the detrimental effects of inservice aging. The staff finds that the applicant has adequately addressed operating experience.

The staff also reviewed the UFSAR Supplement to determine whether it provides an adequate description of the program.

4.4.1.3 Conclusions

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1), that, for the environmental qualification of electrical equipment TLAA, the analyses have been projected to the end of the period of extended operation, or the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR Supplement contains an appropriate summary description of the environmental qualification of electrical equipment TLAA evaluation for the period of extended operation, required by 10 CFR 54.21(d). Therefore, the staff has concluded that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation as required by 10 CFR 54.21(c)(1).

4.4.2 GSI-168, Environmental Qualification of Electrical Components

4.4.2.1 Summary of Technical Information in the Application

Environmental qualification evaluations of electrical equipment are identified as TLAAs for RNP. The evaluations of these TLAAs are considered the technical rationale that the CLB will be maintained during the period of extended operation. The evaluations are provided in Section 4.4.1 of the LRA. Consistent with the above NRC guidance, no additional information is required to address GSI-168 in a renewal application at this time.

4.4.2.2 Staff Evaluation

GSI-168 is now closed. The staff issued RIS 2003-09, "Environmental Qualification of Low-Voltage Instrumentation and Control Cables," on May 2, 2003, and indicated that no further action is required by the applicant.

4.4.2.3 Conclusions

The staff determined that no further action is required by the applicant because GSI-168 is closed.

4.5 Concrete Containment Tendon Loss of Prestress

4.5.1 Summary of Technical Information in the Application

The applicant describes the RNP containment building as a steel-lined concrete shell in the form of a vertical right cylinder with a hemispherical dome and a flat base. The dome and base are constructed of reinforced concrete. The cylinder walls are concrete, reinforced circumferentially and prestressed vertically.

The applicant points out that prestressing force (in vertical direction) is not constant; it decreases over time due to a variety of design conditions. The applicant identifies the factors affecting the prestressing force that were considered in the original evaluation of the containment prestressing tendons as steel relaxation, concrete shrinkage, concrete creep, elastic shortening of concrete, and 2 percent reduction for broken tendons.

For license renewal, the applicant states that the calculation of prestress was updated to address potential losses through the period of extended operation. The new calculation considers the factors listed above that influence loss of prestress. However, the value for concrete shrinkage was marginally reduced based on a comparison to estimated shrinkage values used in the original calculation, as well as reference to the time of application of loading compared to completion of the containment walls. Specifically, the original analysis used a shrinkage coefficient of 0.0003, and the original containment design information estimates the actual shrinkage to be 0.00005. The value used in the revised calculation is 0.0002. This is supported by the fact that shrinkage is a volume change in concrete that occurs with time rather than with load; as such, higher values are more realistic for pretensioned members where the prestress is transferred to the concrete at an early age, whereas the lower value is more appropriate for post-tensioned members. Moreover, the applicant makes a point that RNP tendons are considered to be post-tensioned because the tendons were not loaded until after the concrete was placed. This allowed a portion of the shrinkage to occur prior to tendon tensioning.

Furthermore, the applicant explains that no prestress losses were considered for elastic shortening, due to the retensioning of the tendons approximately a month after the initial tensioning. No reduction in prestress was taken for general corrosion based on review of the 5-year and 25-year surveillance tendon inspections. For example, based on visual examination of the 25-year tendon and upon removal of the grout surrounding the tendon, the applicant noted, "The surface of the bars was covered with a reddish-brown oxide that could be removed simply by wiping the surface clean by hand. No measurable metal loss or etching could be detected once the dust was removed." Therefore, grouting the tendons has proven to be effective for the prevention of corrosion.

The applicant indicates that the calculation projects the prestress losses for 60 years. The applicant also indicates that the tendons were originally tensioned a few months prior to the original licensing date of the plant. As such, the actual prestress period for the tendons is more than 60 years. Based on comparison of the evaluated margin to the required minimum prestress, the slight increase in duration will not allow the actual prestress to go below the required minimum. Based on the above analysis of tendon prestress, the applicant has determined that the final effective prestress at the end of 60 years exceeds the minimum required value. Consequently, the post-tensioning system will continue to perform its intended function throughout the period of extended operation. Therefore, the analysis associated with containment tendon loss of prestress has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.5.2 Staff Evaluation

The RNP is one of the few operating plants in which the containment prestressing tendons are protected from corrosion by means of cement grout. Though the cement grout provides a reliable alkaline medium for protecting the tendons, the tendon system cannot be monitored for either the remaining prestress level, or for the effectiveness of the cement grout in protecting the tendons. Also, some extraneous causes of early deterioration of prestressing tendon systems with greased tendons in the United States are to an extent applicable to the high hardness prestressing system components (e.g., American Iron and Steel Institute (AISI) 5160 bars, AISI 4130 couplers, and AISI 8620 grip nuts) of RNP containment.

In RAI 4.5-1, the staff requested information to understand the basis of the applicant's TLAA. From the TLAA provided, the relative magnitudes of the changes in the various factors affecting the prestressing loss and remaining prestressing force levels are not clear. The applicant was asked to provide a table showing the initial average prestressing force, losses due to the five factors (indicated by bullets in the TLAA), and the final average prestressing force originally considered at 40 years, and the values proposed at the end of the extended period of operation.

In response to RAI 4.5-1, the applicant provided the following table showing the calculated prestressing forces at the initial prestressing, at 40 years, and at 60 years after the installation of the forces.

Description	Initial Value	Value After 1 Year	Value After 50 Years	Value At 60 Years
Prestress losses due to concrete shrinkage	N/A	4002 psi	1998 psi	0
Prestress losses due to concrete creep	N/A	6317 psi	3152 psi	0

Prestress losses due to tendon relaxation	N/A	6000 psi	2400 psi	1800 psi
Prestress losses due to elastic shortening	2104 psi	N/A	N/A	N/A
Tendon prestress	120,000 psi	103,680 psi	96,128 psi	94,328 psi
Minimum required prestress	91,726 psi	91,726 psi	91,726 psi	91,726 psi

The staff reviewed the table in conjunction with the values estimated in the UFSAR. The staff also reviewed the modifications made by the applicant to the UFSAR values and discussed in 4.5.1 of this SER. The staff considers the modifications made to the concrete shrinkage value reasonable and acceptable. Based on the review of the applicant's estimated values at 40 and 60 years, the staff finds that the prestressing force imparted to the containment will be adequate during the period of extended operation.

Knowing the types of materials used for fabricating the tendons and their anchorage components, and their potential for corrosion, the staff in RAI 4.5-2 requested the following information from the applicant:

> Information Notice (IN) 99-10, Revision 1, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments," describes the experience related to hydrogen stress cracking of ASTM A 421 wires, and breakage of AISI 4140 anchor-heads due to hydrogen stress cracking. However, these incidences were detected, and corrective actions were taken as the tendon components were amenable for in-service inspection, component replacement, and re-tensioning, as required.
>
> The RNP tendon components (i.e., AISI 5160 bars, AISI 4130 couplers, and AISI 8620 grip nuts) are high hardness components, subjected to sustained high stresses, and hydrogen stress cracking of the high hardness components is a plausible aging effect in the presence of galvanized tendon ducts around the grouted tendon components. As recognized by the applicant in Revision No. 15 of the UFSAR (page 3.8.1-56), the results of the two surveillance blocks cannot be relied upon to provide confidence regarding the plausibility of such aging effects, or the time dependent trending of prestressing forces. Moreover, no such surveillance blocks are available for the future prediction of the containment tendon behavior.
>
> In light of the above discussion, the applicant is requested to explore the methods that can be used to assess the containment prestressing levels during the extended period of operation.

The RAI essentially requested the applicant to explore the methods that could be used to assess and track the containment prestressing force and potential degradation of prestressing tendon components.

In response, the applicant provided the following information:

- Degradation (breakage) of prestressing wires (as discussed in Information Notice 99-10) was primarily attributed to the ability of moisture to reach unprotected areas; RNP tendons are completely encased in grout and are therefore not susceptible to moisture intrusion.

- Stress-corrosion cracking occurs when high stress, corrosive environment, and susceptible material are present. Only one element is present in RNP containment prestress components (i.e., high stress).

- Surveillance blocks examined at 5 and 25 years showed no corrosion of the embedded tendon material.

- Containment structural integrity tests were performed in 1970, 1974, and 1992, and comparisons are provided to the NRC in a letter dated October 7, 1992 (Serial No. NLS-92-262).
- The prestressing levels have been analytically determined to be sufficient through the period of extended operation. IWL examination will be continued during the EPO.
- To provide additional assurance of the tendon design capacity, tests (at integrated leak rate test pressure) similar to the structural integrity test performed in 1992, will be scheduled to coincide with the first and second Appendix J containment integrated leak rate test during the period of extended operation. The monitoring criteria of these tests will be limited to deformations and cracking associated with the vertical prestressed tendons and will not include radial or axial monitoring. The proposed tests will be performed in conjunction with the analytical determination of tendon prestress, the established corrosion resistance of the embedded tendons, the previously completed structural integrity tests, and the ongoing inspections of concrete.

The staff believes that stress corrosion of the tendon hardware components is a plausible aging effect, and means have to be found to assess the containment integrity during the period of extended operation. In the last bulleted item, the applicant commits to perform structural integrity pressure tests of the RNP containment two times during the extended period of operation. However, the applicant is not clear as to what measurements will be taken during the tests. The staff believes that observing the crack pattern of the containment and measuring the containment deformations during the recommended pressure tests provide a gross means of confirming that a widespread degradation of the prestressing tendon components has not occurred. The staff believes that all means available during the pressure tests should be employed to assess the integrity of the prestressing tendons and the containment.

In Item 45 of the RNP license renewal commitments, the applicant incorporates the staff's recommendations for performing structural integrity testing and making the necessary observations during the tests. The staff finds the applicant's commitment acceptable as it would assess the integrity of the prestressing tendons and the RNP containment during the period of extended operation.

In RAI 4.5-3, the applicant is requested to justify why the information sought in RAI 4.5-1 should not be inserted in the UFSAR Supplement. Having such a table would clearly show the expected average prestressing force level in the tendons and in the concrete of the containment during the extended period of operation.

In Appendix A2 of the LRA, the applicant indicates changes to Section 3.8.1.4.7 of the UFSAR related to the changes in the value of shrinkage and tendon relaxation loss for estimating the final prestress force in the containment at the end of the period of extended operation. The staff recommends that the table provided in response to RAI 4.5-1 be inserted in the UFSAR Supplement or in Section 3.8 of the UFSAR.

In Item 46 of the RNP license renewal commitments, the applicant agrees to incorporate the table in Section 3.8.1.4.7 of the RNP UFSAR.

4.5.3 Conclusions

On the basis of the information provided in Section 4.5 and Appendix A2 of the LRA and in the responses to the staff's RAIs, the staff has concluded that the TLAA for tendon prestressing force performed in accordance with the requirement of 10 CFR 54.21(c)(1)(ii) will be valid for the period of extended operation. This conclusion is based on the assumption that the applicant will be indirectly monitoring the condition of the tendon hardware components by pressure testing of the containment.

4.6 Other TLAAs

4.6.1 Thermal Aging Embrittlement

In Section 4.6.1 of the LRA, the applicant provides its TLAA for assessing the effect of 60-year operation on the thermal aging embrittlement and leak-before-break (LBB) analyses for cast austenitic stainless steel (CASS) materials in the RNP reactor coolant main loop piping and for demonstrating that the LBB analysis for the RNP reactor coolant main loop piping would remain acceptable for service through the expiration of the extended period of operation for RNP, as evaluated in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.6.1.1 Summary of Technical Information in the Application

In Section 4.6.1 of the LRA, the applicant states that the fracture mechanics analyses for the CASS components in the RCS are considered to be TLAAs because of the effects of thermal aging, and that for RNP, these analyses are the LBB analysis of RCS piping and welds and the analysis of RCPs in support of ASME Code, Section XI, Code Case N-481. In this section of the LRA, the applicant summarizes the effects that thermal aging of the CASS reactor coolant piping and pump casing components will have on the LBB analysis for the RNP main RCS piping and Code Case N-481 inspection analyses for RNP RCPs.

In Section 4.6.1 of the LRA, the applicant stated that an LBB analysis was performed to demonstrate that any potential leaks that develop in the RCS loop piping would be detected by plant leak monitoring systems before a postulated throughwall crack (resulting in a leak of the reactor coolant) would grow to unstable proportions during the 40-year plant life. In this section of the LRA, the applicant explained that the RNP LBB assumes the existence of a throughwall crack of sufficient size, such that the resultant leakage can be easily detected by the existing leakage monitoring system, and demonstrates that, even under maximum faulted loads, the assumed crack size is much smaller (with margin) than a critical flaw size that could grow to pipe failure. The applicant stated that the aging effects that need to be addressed during the period of extended operation include thermal aging of CASS materials in the primary loop piping components and fatigue crack growth.

In regard to the applicant's evaluation of the effect of thermal aging on the integrity of the RNP RCPs, the applicant stated that, following ASME approval of Code Case N-481, "Alternate Examination Requirements for Cast Austenitic Pump Casings, Section XI, Division 1," in March 1990, the Westinghouse Owner's Group sponsored WCAP-13045, which provided a generic fracture mechanics analysis and demonstrated generic compliance with the code case for the fleet of Westinghouse-designed light-water reactors. The applicant stated that Code Case N-481 permits surface examination methods to be used in lieu of volumetric examination methods for inspections of RCP casings[2], provided a fracture mechanics analysis is prepared which meets specified requirements. The applicant also stated that the code case requires a plant-specific evaluation to demonstrate safety and serviceability of the pumps and that; therefore, WCAP-15363, Revision 0, was issued in April 2000 as the plant-specific analysis to support use of the alternate inspection techniques for the Westinghouse Model 93 pumps at RNP. The applicant also stated that the plant-specific loadings were compared to the generic loadings in WCAP-13045, and plant-specific materials were compared to generic materials data used in WCAP-13045, demonstrating the requirements of the code case were met for the 40-year operation of the plant.

The applicant stated that, to support the license renewal process, a new report, WCAP-15363, Revision 1, was prepared which supersedes WCAP-15363, Revision 0, and includes an evaluation of the plant-specific pump casing material properties to account for reduced fracture toughness due to thermal embrittlement during the 60-year extended operational period. The applicant stated that WCAP-15363, Revision 1, uses the limiting transients from the 40-year design transient set provided in WCAP-15363, Revision 0, and that the 40-year design transients have been shown to be conservative for 60 years of plant operation. The applicant stated that WCAP-15363, Revision 1, demonstrates that the safety margin requirements for leakage and crack stability of the RNP RCP casings have been met and justify the use of the surface examination of pump casings in lieu of volumetric examination in accordance with the code case throughout the period of extended operation. The applicant stated that, therefore, the ASME Code Case N-481 analysis has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.6.1.2 Staff Evaluation

Thermal aging refers to the gradual change in the microstructure and properties of a material due to its exposure to elevated temperatures for an extended period of time. Thermal aging may reduce the fracture toughness for a given material.[3] When this occurs, the material's critical crack size, which is a bounding material property for any given material, is smaller. Should cracks exist in a component and grow to sizes larger than the critical crack size for the component's material of fabrication, the cracks are considered to be unstable and will propagate rapidly through the component. This phenomenon is referred to by materials and mechanical engineers as crack growth by fast fracture. Cracks that propagate unstably by this phenomenon may lead to catastrophic failure of the component. CASS components are known to be particularly susceptible to reduction in fracture toughness as a result of thermal aging; neutron embrittlement of CASS internals may enhance this effect. When this occurs, a CASS component' s tolerance to withstand the presence of existing flaws (cracks) is significantly reduced.

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[2]The applicant's statement is slightly in error. ASME Code Case N-481 actually provides alternative visual examination requirements for Class 1 pump casings fabricated from CASS. Licensees seeking to apply the alternative requirements in the Code Case to their RCP casings are required by the alternative provision requirements of 50.55a(a)(3)(i) to Title 10, *Code of Federal Regulations*, to submit the methods for NRC review and approval. The alternative inspection visual methods include alternative VT-1, VT-2, and VT-3 requirements. The alternative requirements in Code Case N-481 also require the licensee applying to use the code case methods to submit an alternative fracture mechanics analysis for the pump casings that supports use of the alternative inspection requirements.

[3]Fracture toughness refers to a material property that is an indication of a material's resistance to rapid unstable crack propagation. For metallic alloys, fracture toughness properties are, in part, dependent upon an alloy's microstructural configuration and alloying content.

The RNP Class 1 RCS main loop piping includes some piping, valve, and pump casings fabricated from CASS. The only significant effects of the additional period of operation on the structural integrity of the Class 1 RCS at RNP are on the LBB analysis for the RCS main loop piping components fabricated from CASS, and on the fracture mechanics analysis that is required to support use of alternative inspection methods proposed for the RNP RCP casings fabricated from CASS. The staff evaluates the effect of the additional period of operation on the structural integrity assessment for these items in the paragraphs that follow.

The RNP LBB Analysis for the Main Loop RCS Piping and Components

In Section 4.6.1 of the LRA, the applicant indicated that it performed a new LBB analysis to assess the effect of 60 years of operation on the acceptability of the previous LBB analysis for RNP. The applicant stated that the new LBB analysis and calculation is contained in proprietary Class 2 report WCAP-15628, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the H.B. Robinson Unit 2 Nuclear Power Plant for the License Renewal Program [July 2001]," and that this report includes allowances for reduction of fracture toughness of CASS due to thermal embrittlement during a 60-year operating period. The applicant stated that the new LBB analysis meets the requirements for LBB required by 10 CFR 50, Appendix A, General Design Criterion 4, and uses the recommendations and criteria from the NRC Standard Review Plan for LBB evaluations. The applicant stated that the new LBB analysis uses the prior 40-year design basis thermal transients as input for the fatigue crack growth analysis and that these transients have been shown to be conservative for the 60-year operating period. The applicant therefore concluded that the RCS primary loop piping LBB analysis has been projected to the end of the period of extended operation, and has been demonstrated to be acceptable through the expiration of the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

The applicant's TLAA for the LBB for the RCS main loop piping did not indicate whether WCAP-15628 was reviewed and approved by the NRC. The applicant's TLAA for LBB also did not discuss why the applicant considered the 40-year design basis thermal transients to be conservative and bounding for the LBB analysis through the expiration of the extended operating period for RNP or discuss how the LBB analysis accounted for potential loss of fracture toughness properties that could result from thermal aging of RCS main loop piping, pump, or valve components made from CASS. Therefore in RAI 4.6.1-1, the staff requested that the applicant submit WCAP-15628 for review and approval.

In response to RAI 4.6.1-1 and by letter dated May 7, 2003, the applicant submitted Westinghouse proprietary Class 2 report WCAP-15628 for review and approval. The staff has completed its review of WCAP-15628. Regarding the adequacy of the fatigue crack growth analysis through the expiration of the extended operating period for RNP using the original 40-year design basis thermal transients, the applicant summarized RNP's 40-year thermal fatigue design transients, the number of actual plant transients that have occurred through 2000, and the 60-year projection methods and basis for the LBB analysis. This summary indicates that the projected number of occurrences through 60 years of licensed life are bounded by the number of transients originally assumed in the 40-year fatigue analysis. In regard to the concern about the thermal aging of RCS main loop piping and components made from CASS, the staff has verified that the applicant considered appropriate, fully-aged toughness for CASS in the original 40-year LBB analysis. Based on the above evaluation, the staff agrees with the applicant's conclusion that this TLAA is in accordance with

10 CFR 54.21(c)(1)(ii), and the LBB application for the primary loop piping and components is acceptable for the period of extended operation.

Effect of Thermal Aging on the Inspection Methods Proposed for the RNP Reactor Coolant Pumps

The 1995 edition of the ASME Boiler and Pressure Vessel Code, Section XI, Table IWB-2500-1, Examination Category B-L-1, Item B12.10, requires that volumetric examinations be performed on ASME Class 1 pump casing welds once every 10-year inservice inspection (ISI) interval. ASME Code Case N-461 provides alternative ISI techniques for examinations of RCP casings in PWR-designed light-water reactors. The methods of the code case allow a licensee to use the following alternative requirements for assuring the integrity of RCP casings made from CASS in lieu of performing the volumetric examination methods required by ASME Section XI, Table IWB-2500-1, Examination Category B-L-1, Item B12.10:

- perform a VT-2 visual examination of the exterior of all pumps during the hydrostatic
- pressure test required by Table IWB-2500-2, Examination Category B-P
- perform a VT-1 visual examination of the external surfaces of the weld on one casing
- perform a VT-3 visual examination of the internal surfaces whenever a pump is disassembled for maintenance
- perform an evaluation that includes the following elements and that is required to be submitted to the NRC for review:

—an analysis of the material properties of the pump casing, including the fracture toughness value

—a stress analysis for the pump casing

—a review of the operating history for the pump

—postulation of an existing reference flaw that has a flaw depth equal to one-quarter the pump casing thickness and a flaw length equal to six times the postulated flaw depth (i.e., a quarter-thickness flaw that has an aspect ratio of 6:1)

—establishment of stability criteria for the postulated flaw under the governing stress conditions

—consideration of the effects of thermal aging embrittlement and any other processes or mechanisms that may degrade the properties of the pump casing during service

Pursuant to 10 CFR 54.21(c)(1)(i), in order to demonstrate that the TLAA for the RNP RCP casing will remain valid for the period of extended operation, the applicant stated that WCAP-15363, Revision 0, was issued by Westinghouse to justify use of the Code Case N-481 for the inspections of the RNP RCP casings during the current operating term and that WCAP-15636, Revision 1, was issued to justify use of the Code Case N-481 for the inspections of the RNP RCP casings through the expiration of the extended operating term for RNP. In response to RAI 4.6.1-2, by letter dated May 7, 2003, the applicant submitted Westinghouse proprietary Class 2 report WCAP-15363, Revision 1, "A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of H.B. Robinson Unit 2 for the License Renewal Program," for review and approval.

In Section B.4.2 of Appendix B to the LRA, the applicant has stated that the program attributes for the CASS Program are consistent with those specified in AMP XI.M12 of the Generic Aging Lessons Learned (GALL) Report. In AMP XI.M12, it is stated that the existing ASME Section XI requirements, including the alternative requirements of ASME Code Case N-481 for RCP casings, are adequate for all RCP casings and valve bodies. It is also stated in the program element for *Detection of Aging Effects* that, for RCP casings and valve bodies but not susceptible piping, no additional inspection or evaluations are required to demonstrate that the material has adequate fracture toughness.

The staff notes that the ASME Code Section XI Inservice Inspection Program is required to be updated by the applicant and reviewed by the staff every 10-year ISI interval. The acceptability of using Code Case N-481 as an alternative requirement for the ISI of RCP casings will be evaluated by the staff during the review of the applicant's Inservice Inspection Program, which is required to be submitted for NRC approval every 10years. Therefore, it is more appropriate for the staff to review the applicant's fracture mechanics analysis during the staff's review of the applicant's ISI program for the 10-year interval. Based on the consideration discussed above, the staff has determined that there is no need to review the applicant's fracture mechanics analysis as documented in WCAP-15636, Revision 1, to support the use of Code Case N-481 for inservice inspection of RCP casings during the extended period of operation for RNP. Therefore, the staff concludes that a TLAA on the fracture toughness analysis used for supporting the application of Code Case N-481 to the in-service inspections of the RCP casings is not necessary for the RNP LRA, as would otherwise be mandated by 10 CFR 54.21(c)(1).

4.6.1.3 Updated Final Safety Analysis Report Supplement

The applicant provides the following UFSAR Supplement summary description for the LBB analysis of RCS piping In Section A.3.2.5.1 of Appendix A of the LRA:

> WCAP-15628... is a new leak-before-break (LBB) calculation applicable to RNP large bore reactor coolant system (RCS) piping and components that includes allowances for reduction of fracture toughness of cast austenitic stainless steel due to thermal embrittlement during a 60-year operating period. The new analysis meets the requirements for LBB required by 10 CFR 50, Appendix A, General Design Criterion 4, and uses the recommendations and criteria from the NRC Standard Review Plan for LBB evaluations. The new analysis uses the 40-year design basis thermal transients as input for the fracture mechanics analyses. These transients have been shown to be conservative for the 60-year operating period. Therefore, the RCS primary loop piping Leak-Before-Break analysis has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

The applicant provides an UFSAR Supplement summary description for the fracture mechanics analysis of the RNP RCP casing in Section A.3.2.5.2 of Appendix A of the LRA. However, as discussed in Section 4.6.1.2, the UFSAR Supplement for the fracture mechanics analysis of the RNP RCP casing, as documented in WCAP-15363, Revision 1, is not needed for the applicant's LRA, because this analysis will be reviewed during the staff's review of the applicant's Inservice Inspection Program, which will be submitted by the applicant for NRC approval every 10 years.

The applicant's UFSAR Supplement summary description of the TLAA on thermal aging of CASS indicates that the TLAA is in compliance with the requirements of 10 CFR 54.21(c)(1)(ii). This TLAA is based on WCAP-15628, which was issued to demonstrate the validity of the existing 40-year LBB analysis for the period of extended operation for RNP. Therefore, in RAI 4.6.1-3, the staff requested clarification as to whether the UFSAR Supplement summary description for the TLAA of thermal aging of CASS, as given in Section A.3.2.5.1 of Appendix A of the LRA, should indicate compliance with the requirements of 10 CFR 54.21(c)(1)(i) instead of with the requirements of 10 CFR 54.21(c)(1)(ii). In the RAI, the staff also requested that the UFSAR Supplement summary descriptions for the TLAA of LBB analysis for the main RCS loop piping at RNP, as given in Sections A.3.2.5.1 of Appendix A of the LRA, be amended to reflect the information provided in Carolina Power and Light Company's (CP&L's) response to RAI 4.6.1-1, when the response is submitted under oath and affirmation to the NRC document control desk.

In its response to RAI 4.6.1-3, dated April 28, 2003, the applicant clarified that the LBB analysis performed for license renewal incorporates plant-specific material property data and adjustments to material property data to account for changes projected to occur during the license renewal period. Therefore, the LBB analysis has been performed to demonstrate that the margins of safety on acceptable flaw size and stability are acceptable, as projected through the expiration of the extended period of operation for RNP and evaluated against the criterion stated in 10 CFR 54.21(c)(1)(ii).

The UFSAR Supplement summary description on the TLAA for LBB (as given in Section A.3.2.5.1 of Appendix A of the LRA) provides a summary description of the 60-year LBB analysis for the RNP primary loop piping. Since the UFSAR Supplement summary description refers to the applicable safety assessments for this analysis, and since the applicant's response to RAI 4.6.1-3 provides the applicant's basis for assessing this analysis against the criterion stated in 10 CFR 54.21(c)(1)(ii), the staff concludes that this UFSAR Supplement summary description for the TLAA on LBB provides sufficient details as to how the analysis will remain valid, as projected through the expiration of the extended period of operation for RNP.

The staff therefore concludes that the UFSAR Supplement summary description provided in Section A3.2.5.1 of Appendix A of the LRA is acceptable, and RAI 4.6.1-3 is resolved.

4.6.1.4 Conclusions

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that for the TLAAs on thermal aging of CASS RCS components, the analyses remain valid through the end of the period of extended operation. The staff also concludes that the UFSAR Supplement contains an appropriate summary description of the TLAA on thermal aging of CASS for the period of extended operation, as required by 10 CFR 54.21(d). Therefore, the staff has concluded that the safety margins established and maintained during the current operating term for the primary reactor coolant loop piping will be maintained until the expiration of the period of extended operation as required by 10 CFR 54.21(c)(1).

4.6.2 Foundation Pile Corrosion

4.6.2.1 Summary of Technical Information in the Application

The applicant identified in the LRA that corrosion of Class 1 structure foundation piles is a TLAA based on the evaluation of the piles for a 40-year corrosion loss. The applicant indicated the original analysis determined that the possibility of active corrosion is minimal and corrosion losses would be negligible because the measured soil resistivity values are so high. This analysis relies on plant-specific data regarding soil resistivity and industry data from NUREG-1557 and EPRI TR-103842.

The RNP UFSAR states that, "Any steel structure in soil (even without the protection afforded by concrete) is progressively less susceptible to corrosion as the electrical resistivity of the soil increases. Soil resistivity measurements taken in August 1958, prior to construction of Unit 1 and as reconfirmed by measurements taken at the construction site in December, 1966, have established that the soil resistivity is so high that the possibility of active corrosion is minimal."

The applicant stated in the LRA that it performed a reanalysis of foundation pile corrosion for license renewal and determined that corrosion losses would continue to remain nonsignificant for the period of extended operation. It concluded that corrosion will not prevent the foundation piles from performing their license renewal intended functions. Furthermore, the applicant stated that its conclusion is consistent with the recommendations and findings of NUREG-1557 and EPRI TRA 103842 and is in accordance with the estimated corrosion losses developed in the original analysis.

4.6.2.2 Staff Evaluation

The staff notes that NUREG-1557, "Summary of Technical Information and Agreements from Nuclear Management and Resources Council Industry Reports Addressing License Renewal," identifies corrosion of steel piles as a "Nonsignificant ARDM." It further states, "Steel piles driven in undisturbed soils have been unaffected by corrosion & those driven in disturbed soil experience minor to moderate corrosion to a small area of metal." The staff also reviewed EPRI TRA 103842, "Class I Structures License Renewal Industry Report," and found the following statement:

> Romanoff examined corrosion data from 43 piling installations and on that basis drew some general conclusions regarding the corrosion of driven steel piles. These test installations had pile depths of up to 136 feet and time of exposure varying from 7 to 50 years in a wide variety of soil conditions. Romanoff's review of this data indicates that the type and amount of corrosion observed on steel pilings driven into undisturbed natural soil, regardless of the soil characteristics and properties, is not sufficient to significantly affect the strength of pilings as load bearing structures. The data also indicate that undisturbed soils are so deficient in oxygen at levels a few feet below the ground surface or below the water table, that steel piles are not appreciably affected by corrosion, regardless of the soil type or the soil properties.

Based on the recommendations and findings of NUREG-1557 and EPRI TRA 103842, and results of the applicant's reanalysis of foundation pile corrosion for license renewal, the staff concurs that corrosion losses would continue to remain insignificant for the period of extended operation.

4.6.2.3 Conclusions

The staff reviewed the TLAA regarding the foundation pile corrosion in accordance with the estimated corrosion losses developed in the original analysis and projected in the reanalysis. The conclusion of the reanalysis is consistent with the recommendations and findings of NUREG-1557 and EPRI TRA 103842. The staff finds that the foundation pile corrosion reanalysis results have been projected to the end of the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1).

The staff also reviewed the UFSAR Supplement for this TLAAs and finds that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

4.6.3 Elimination of Containment Penetration Coolers

4.6.3.1 Summary of Technical Information in the Application

As stated in the LRA, in 1995, an evaluation was performed to justify eliminating the need for cooling water flow to the hot pipe containment penetration coolers to the maximum extent possible. As part of this effort, insulation was credited to reduce the temperature of the concrete surrounding the hot pipe penetrations. The performance requirement for the hot pipe penetrations was to maintain the surrounding concrete temperature below 200 °F under normal operating conditions and other long term conditions.

As part of this effort, insulation was credited to reduce the temperature of the concrete surrounding the hot pipe penetrations. The performance requirement for the hot pipe penetrations was to maintain the surrounding concrete temperature below 200 °F under normal operating conditions and other long term conditions.

Residual heat removal (RHR) system penetration S-15 did not require cooling water to be maintained because the concrete temperature around S-15 only exceeded 200 °F during short duration transients and the temperature then was less than 350 °F. In addition, the steady-state temperature without cooling water and continuous RHR flow at 380 °F results in the temperature of the surrounding concrete of approximately 210 °F.

The analysis of concrete temperature determined that the allowable number of cycles of heatup and cooldown, at 40 hours or less per cycle, was 252 cycles. This is the total number of heatup/cooldown cycles the concrete surrounding the S-15 RHR penetration could experience temperatures greater than 200 °F over the balance of plant life figured from 1995. The balance of plant life was projected as 16 years (out of 40 years total plant life) when this calculation was issued in 1995. The allowable number of cycles was compared to the maximum number of heatup/cooldown cycles projected to the end of the period of extended operation.

Because the projected number of cycles for 60-years of operation (120 cycles) is less than the allowed number of cycles for penetration S-15 (252 cycles), the evaluation concluded that the analysis remains conservative and bounding for the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

4.6.3.2 Staff Evaluation

The LRA states that "the analysis of concrete temperature determined that the allowable number of cycles of heatup and cooldown, at 40 hours or less per cycle, was 252 cycles." The LRA further states, "Because the projected number of cycles for 60-years of operation (120 cycles) is less than the allowed number of cycles for penetration S-12 (252 cycles), the evaluation concluded that the analysis remains conservative and bounding for the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(i)." The staff requested the applicant to describe how the analysis was performed and submit the analysis results of concrete properties at the end of 252 cycles. The applicant provided the following response to RAI 4.6.3-2:

- The concrete heatup and cooldown temperatures range from 200 °F to 210 °F during reactor coolant system heatup and 210 °F to 200 °F during reactor coolant system cooldown.

- A thermal fatigue analysis was not performed.

- An evaluation was developed that justified operation with cooling water isolated to the RHR penetrations for a continuous period of approximately 18 months. Cooling water was actually isolated to the RHR penetration for less than 4 months between RFO-15 and -16, leaving the equivalent of 14 months (or 10,080 hours) of "unused" operation with cooling water isolated. The available time of 10,800 hours is equivalent to 252 cycles of heatup/cooldown based on 40 hours per cycle. The 252 cycles of heatup/cooldown bound the projected number of heatup/cooldown cycles (120) and the design heatup/cooldown cycles (200) shown in LRA Section A.2.1.1. The RHR penetrations are subject to high temperatures only during RHR operation, because the RHR system operates only during the heatup and cooldown cycles, not during normal plant operation. No disintegration or physical degradation of the concrete was predicted under the above-described operating conditions. The subject evaluation determined a 25 percent reduction in compressive strength due to temperature effects; however, the reduced compressive strength was still greater than the concrete design strength (3000 psi) that was used in original concrete calculations. The reduced concrete strength (3010 psi) at the penetration was determined to be acceptable. This determination was conservative because the actual concrete compressive strengths from field testing were higher than that used in the evaluation, and the actual temperatures are less than the 277 °F used in the evaluation.

The staff also requested the applicant to clarify whether the conclusion of 252 cycles was obtained from its operating experience. During a teleconference call on June 10, 2003, the applicant stated it had found an analysis result indicating that the temperature in concrete around the containment penetration would always remain below 200 °F. Therefore, the applicant proposed to withdraw this TLAA item in LRA Section 4.6.3. The staff agreed with the applicant's approach of withdrawing this TLAA issue because its analysis results indicate that there is no need for the TLAA. The applicant submitted a letter dated August 14, 2003, to withdraw this TLAA item from the LRA.

4.6.3.3 Conclusions

Since the applicant's analysis results indicate that the concrete temperature around the containment penetration will always remain below 200 °F with the elimination of containment penetration coolers, the applicant has withdrawn this TLAA issue from LRA Section 4.6.3. The staff finds the applicant's response to be acceptable, and Confirmatory Item 4.6.3-1 is closed.

4.6.4 Aging of Boraflex

4.6.4.1 Summary of Technical Information in the Application

In LRA Section 4.6.4, the applicant describes the TLAA for the degradation of Boraflex, which is a boron carbide dispersion, in an elastomeric silicone that is currently used in the spent fuel storage racks as a neutron absorber. The base polymer of Boraflex has been shown to degrade in the borated water environment of the spent fuel pool and under the influence of gamma radiation. Degradation effects include leaching of boron from the polysiloxane matrix, which results in diminished neutron absorption capability of the Boraflex panels.

The applicant references the following NRC INs and Generic Letter (GL) that have identified the concern of the aging of Boraflex neutron-absorbing material:

- IN 87-43, "Gaps in Neutron-Absorbing Material in High-Density Spent Fuel Storage Racks"
- IN 93-70, "Degradation of Boraflex Neutron Absorber Coupons"
- IN 95-38, "Degradation of Boraflex Neutron Absorber in the Spent Fuel Storage Racks"
- GL 96-04, "Boraflex Degradation in Spent Fuel Pool Storage Racks"

In its response to GL 96-04, the applicant commits to continue monitoring and performing analyses of the Boraflex degradation at RNP. In the LRA, Section 4.6.4, the applicant states that it will continue the existing coupon monitoring program as required during the period of extended operation. The applicant also commits to continue monitoring spent fuel pool silica levels and performing silica evaluations.

In the LRA, the applicant has identified aging of Boraflex in the spent fuel pool racks plate as a TLAA. The staff evaluates the TLAA for aging of Boraflex based on the information presented in Section 4.6.4 of the LRA and the applicant's response to the staff's RAI.

4.6.4.2 Staff Evaluation

In LRA Section 4.6.4, the applicant describes the TLAA for the degradation of Boraflex, which is a boron carbide dispersion, in an elastomeric silicone that is currently used in the spent fuel storage racks as a neutron absorber. The base polymer of Boraflex has been shown to degrade in the borated water environment of the spent fuel pool and under the influence of gamma radiation. Degradation effects include leaching of boron from the polysiloxane matrix, which results in diminished neutron absorption capability of the Boraflex panels.

In LRA Section 4.6.4, the applicant stated that prior to the extended period of operation, either an analysis will be performed to permit the elimination of the credit for the Boraflex panels in the spent fuel racks in determining K_{eff} for the spent fuel array, or credit will be taken for the current Boraflex monitoring program which will be evaluated against the GALL Report.

In its April 28, 2003, letter, in Commitment No. 47, the applicant stated that the current Boraflex monitoring program will be evaluated against the requirements for a license renewal AMP, and the results of the evaluation will be documented in the UFSAR. The applicant may withdraw this commitment if its planned analysis to credit soluble boron successfully eliminates credit for the Boraflex sheets in the spent fuel racks.

In its response to RAI 4.6.4-1 dated April 28, 2003, the applicant stated that it currently intends to request a technical specifications (TS) change to eliminate the credit for the Boraflex monitoring program. The proposed TS change is expected to be consistent with similar changes that have been approved for other licensees and represents a reasonable approach for resolution of Boraflex degradation. The applicant also stated that the revised analysis is expected to credit soluble boron and fuel assembly burnup in the reactivity analysis and is based on an approved methodology. Upon NRC approval of the proposed TS change, the license renewal intended function provided by Boraflex panels will no longer be applicable, and the current Boraflex monitoring procedure will be terminated.

By letter dated May 28, 2003, the applicant submitted for staff review a license amendment to change the TS to credit a combination of soluble boron and controlled fuel loading patterns and therefore remove Boraflex monitoring procedures. The staff asked for confirmation that the license amendment to remove the requirements to credit the Boraflex panels from the RNP TS has been approved and that the Boraflex panels will no longer be needed to maintain the K_{eff} for the geometry of the spent fuel rods stored in the spent fuel pool within acceptable levels. As part of this confirmatory item, the staff asked the applicant to provide a reference regarding the staff's safety evaluation to CP&L approving the license amendment for the Boraflex panels. The staff required a commitment statement from the applicant, saying that, "if the NRC staff denies the applicant's request to eliminate and modify, if necessary, the current boraflex monitoring procedure to satisfy the NRC's requirement for the license renewal Boraflex TLAA, and the results of the evaluation will be documented in the UFSAR and the Boraflex monitoring TLAA will be implemented as a part of license renewal." This is Confirmatory Item 4.6.4-1.
By letter dated December 22, 2003, License Amendment 198, the staff approved the applicant's request to eliminate the need to credit the Boraflex neutron absorbing material for reactivity control in the spent fuel storage pool. In place of Boraflex material (i.e., panels), the staff approved the applicant's request to take credit for a combination of soluble boron and controlled fuel loading patterns in the spent fuel pool to maintain the required subcriticality margins in the spent fuel storage pool. On the basis of License Amendment 198, the staff finds that Confirmatory Item 4.6.4-1 is closed. In addition, the applicant may eliminate its Commitment No. 47 and eliminate any discussion in the RNP UFSAR regarding the Boraflex TLAA or the Boraflex monitoring program.

4.6.4.3 Updated Final Safety Analysis Report Supplement

As indicated in the applicant's response to RAI 4.6.4-1, the applicant has indicated that it plans to stop taking credit for the Boraflex program and that, therefore, it will not be necessary for the applicant to include a summary description of the Boraflex TLAA in the UFSAR Supplement.

On the basis of License Amendment 198, issued on December 22, 2003, the applicant may at its own volition, eliminate the UFSAR Supplement summary description for the TLAA for the boraflex panels .

4.6.4.4 Conclusions

As discussed in License Amendment 198, issued on December 22, 2003, the staff approved the applicant's request to credit soluble boron and controlled fuel loading patterns to maintain the required subcriticality margins in the spent fuel storage pool. The staff also approved the applicant's request to eliminate the need to credit the Boraflex neutron absorbing material for reactivity control in the spent fuel storage pool. The Boraflex panels will no longer be used. Therefore, it is not necessary for the applicant to include a TLAA on degradation of Boraflex as part of the LRA.

5 REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The NRC staff issued its safety evaluation report (SER) with open items related to the renewal of operating licences for H.B. Robinson Steam Electric Plant, Unit 2, on August 25, 2003. On September 30, 2003, the applicant presented its license renewal application, and the staff presented its review findings, to the ACRS Plant License Renewal Subcommittee. The staff reviewed the applicant's responses to SER open and confirmatory items and completed its review of the license renewal application. The staff's evaluation is documented in an SER that was issued by letter dated January 20, 2004.

During the 510th meeting of the ACRS, March 3-6, 2004, the ACRS completed its review of the Robinson license renewal application and the NRC staff's SER. The ACRS documented its findings in a letter to the Commission dated March 18, 2004. A copy of this letter is provided on the following pages of this SER Chapter.

March 18, 2004

The Honorable Nils J. Diaz
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT 2

Dear Chairman Diaz:

During the 510th meeting of the Advisory Committee on Reactor Safeguards, March 3-6, 2004, we completed our review of the License Renewal Application (LRA) for the H. B. Robinson Steam Electric Plant, Unit 2, known as Robinson Nuclear Plant, and the related final Safety Evaluation Report (SER) prepared by the NRC staff. Our Plant License Renewal Subcommittee reviewed this application and the staff's initial SER during a meeting on September 30, 2003. During these reviews, we had the benefit of discussions with representatives of the NRC staff and the Carolina Power and Light Company (CP&L). We also had the benefit of the documents referenced.

CONCLUSIONS AND RECOMMENDATIONS

1. The programs instituted and committed to by CP&L to manage age-related degradation are appropriate and provide reasonable assurance that the Robinson Nuclear Plant can be operated in accordance with its current licensing basis for the period of extended operation without undue risk to the health and safety of the public.

2. The CP&L application for renewal of the operating license for Robinson Nuclear Plant should be approved.

BACKGROUND AND DISCUSSION

This report fulfills the requirements of 10 CFR 54.25, which states that the ACRS should review and report on all license renewal applications. In its application, CP&L requested renewal of the operating license for the Robinson Nuclear Plant for 20 years beyond the current license term, which expires on July 31, 2010. Robinson Nuclear Plant is a Westinghouse-designed, three-loop, pressurized-water reactor rated at 2,339 megawatts-thermal (MWt) with replacement steam generators installed in 1984. It is located adjacent to Unit 1 of the H.B. Robinson Steam Electric Plant, a coal fired steam power plant. The LRA was prepared in accordance with NUREG 1801, The Generic Aging Lessons Learned Report.

The Robinson Nuclear Plant final SER documents the results of the staff's review of the information submitted by the applicant, including commitments that were necessary to resolve open and confirmatory items identified by the staff in the initial SER and those identified during onsite NRC inspections and audits. In particular, the staff reviewed the completeness of the applicant's identification of structures, systems, and components that are within the scope of license renewal, the integrated plant assessment process, the identification of the plausible aging mechanisms associated with passive long-lived components, the adequacy of the aging management programs, and the identification and assessment of time limited aging analyses (TLAAs) requiring review.

Several design features that are unique to Robinson Nuclear Plant, such as grouted tendons, containment liner insulation, and some shared systems with a fossil unit, were identified. All shared systems are included in the scope of the LRA.

Robinson Nuclear Plant site has aggressive ground water due to a low pH. The applicant has committed to inspect the dam spillway and the intake structures every 10-years and will also perform opportunistic inspections of inaccessible concrete structures.

The pressurizer spray head is not in scope and, given its importance for cooldown, we questioned its omission. The applicant responded that the accident-basis analysis for plant operation does not include pressurizer spray so its exclusion is permissible. The applicant further stated that degradation of the nozzle would be noticed during normal operation.

The applicant stated that the plant has 37 existing aging management programs, of which 27 have been enhanced, and 10 new programs have been added. Several of these programs have yet to be developed and they will require NRC approval. As with other applicants, we encouraged CP&L to establish a schedule for implementing these commitments well ahead of the beginning of the license renewal period so as not to place an unreasonable demand on both the applicant and NRC resources. CP&L has committed to have 18 of these programs in place by mid 2004.

Time limited aging analyses were performed by the applicant to evaluate reactor vessel neutron embrittlement, metal fatigue for certain components, environmental qualification, grouted concrete containment tendon prestress, boraflex aging, and foundation pile corrosion. All these issues have been resolved satisfactorily. In the case of reactor vessel neutron embrittlement, the staff performed independent calculations and found the applicant's analysis acceptable.

We agree with the staff's conclusion that all open and confirmatory items have been closed appropriately. We conclude that on the basis of our review of the final SER, the LRA, and the NRC inspection and audit reports, there are no issues, specifically related to the matters described in 10 CFR 54.29(a)(1) and (a)(2), that preclude renewal of the operating license for the plant. The programs instituted and committed to by CP&L to manage age-related degradation are appropriate and provide reasonable assurance that the plant can be operated in accordance with its current licensing basis for the period of extended operation without undue risk to the health and safety of the public. The CP&L application for renewal of the operating license for the Robinson Nuclear Plant should be approved.

Sincerely,

/RA/

Mario V. Bonaca
Chairman

References:

1. U.S. Nuclear Regulatory Commission, "Final Safety Evaluation Report Related to H. B. Robinson Steam Electric Plant, Unit 2," January 2004.
2. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report with open items Related to the License Renewal of the H. B. Robinson Steam Electric Plant, Unit 2," August 2003.
3. Letter from J. W. Moyer, Carolina Power and Light Company, to the U.S. Nuclear Regulatory Commission, Subject: Application for Renewal of Operating License, H. B. Robinson Steam Electric Plant, Unit 2, June 14, 2002.
4. NRC Inspection Report 50-261/03-08, H.B. Robinson Steam Electric Plant, May 8, 2003.
5. NRC Inspection Report 50-261/03-09, H.B. Robinson Steam Electric Plant, July 31, 2003.

6 CONCLUSIONS

The staff reviewed Robinson Nuclear Plant (RNP) license renewal application in accordance with Commission regulations and NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," dated July, 2001. In 10 CFR 54.29, the staff identifies the standards for issuance of a renewed license.

On the basis of its evaluation of the application as discussed above, the staff has determined that the requirements of 10 CFR 54.29 have been met.

The staff notes the requirements of Subpart A of 10 CFR Part 51 are documented in NUREG-1437, Supplement 13, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," dated December 12, 2003.

Appendix A: Commitment Listing

During the review of the RNP LRA by the NRC staff, the applicant made commitments to provide aging management programs (AMPs) to manage aging effects of structures and components (SCs) prior to the period of extended operation. The following table lists these commitments, along with the implementation schedule and the source of the commitment.

ITEM NUMBER	COMMITMENT	UPDATED FINAL SAFETY ANALYSIS REPORT (UFSAR) SUPPLEMENT LOCATION	IMPLEMENTATION SCHEDULE	SOURCE
1. Quality Assurance Program	Quality Assurance Program. Existing program is credited. See note below.	A.3.1		
2. 10 CFR 54.37(b) Requirements	Upon issuance of the renewed license, guidance will be incorporated into administrative control procedures that manage the RNP configuration control process to ensure that the requirements of 10 CFR 54.37(b) are met.	A.3.1	Following issuance of renewed license	Request for Additional Information (RAI) 2.1.1-2

3. NUREG-1801 GALL Report	Prior to the period of extended operation, a statement will be incorporated into the UFSAR Supplement description of the programs to document consistency of RNP AMP with programs defined in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report." For RNP programs that are consistent with NUREG-1801, the program description will be revised to state "This program is consistent with the corresponding program described in the GALL Report."	A.3.1	Prior to the period of extended operation	RAI B.1-1
4. ASME Section XI, Subsection IWB, IWC, and IWD Program	ASME Section XI, Subsection IWB, IWC, and IWD Program. Existing program is credited. No changes required. See note below.	A.3.1.1		
5. Water Chemistry Program	Water Chemistry Program. Existing program is credited. No changes required. See note below.	A.3.1.2		
6. Reactor Head Closure Studs Program	Reactor Head Closure Studs Program. Existing program is credited. No changes required. See note below.	A.3.1.3		
7. Steam Generator Tube Integrity Program	Steam Generator Tube Integrity Program. Existing program is credited. No changes required. See note below.	A.3.1.4		

8. Closed-Cycle Cooling Water System Program	Closed-Cycle Cooling Water System Program. Existing program is credited. No changes required. See note below.	A.3.1.5		
9. ASME Section XI, Subsection IWF Program	ASME Section XI, Subsection IWF Program. Existing program is credited. No changes required. See note below.	A.3.1.6		
10. 10 CFR 50, Appendix J Program	10 CFR 50, Appendix J Program. Existing program is credited. See note below.	A.3.1.7		
11. Flux Thimble Eddy Current Inspection Program	Flux Thimble Eddy Current Inspection Program. Existing program is credited. See note below.	A.3.1.8		
12. Fire Protection Program	The Fire Protection Program will be enhanced to note that concrete surface inspections performed under structures monitoring procedures are credited for inspection of fire barrier walls, ceilings, and floors.	A.3.1.9	Prior to the period of extended operation	LRA, Appendix B, Section B.3.1

13. Boric Acid Corrosion Program	The scope of the Boric Acid Corrosion Program will be expanded to (1) ensure that the mechanical, structural, and electrical components in scope for license renewal are addressed and (2) identify additional areas in which components are susceptible to exposure from boric acid.	A.3.1.10	Prior to the period of extended operation	LRA, Appendix B, Section B.3.2
14. Flow-Accelerated Corrosion Program	The Flow-Accelerated Corrosion Program will be modified to (1) include additional components potentially susceptible to flow-accelerated corrosion and/or erosion, and (2) clarify when condition reports shall be initiated.	A.3.1.11	Prior to the period of extended operation	LRA, Appendix B, Section B.3.3
15. Bolting Integrity Program	The following will be implemented: (1) administrative controls for bolting will be modified to prohibit the use of MoS_2 compounds in high-strength bolting applications, and (2) an inspection and evaluation will be performed on high-strength bolting used on one motor-operated valve to determine susceptibility for cracking.	A.3.1.12	Prior to the period of extended operation	LRA, Appendix B, Section B.3.4
16. Open-Cycle Cooling Water System Program	An activity will be scheduled in the site Preventive Maintenance Program to replace cooling coils in the emergency core cooling system room coolers on a prescribed frequency.	A.3.1.13	Prior to the period of extended operation	LRA, Appendix B, Section B.3.5

17. Inspection of Overhead Heavy Load and Light Load Handling	Administrative controls for inspection of overhead heavy load and light load handling will be enhanced to (1) include requirements for inspecting the turbine gantry crane in addition to the other cranes that require inspection, (2) note that cranes are to be inspected using the attribute inspection checklist for structures, and (3) revise the attribute inspection checklist for structures to include GALL terminology such as wear.	A.3.1.14	Prior to the period of extended operation	LRA, Appendix B, Section B.3.6 RAI B.3.6-2

18. Fire Water System Program	The Fire Water System Program will be modified to include—<u>Fire Protection Sprinkler Systems</u> (1) For sprinkler heads in service for 50 years, either sprinkler head replacement or sampling/field service testing of heads in accordance with National Fire Protection Association (NFPA) 25 requirements based on the inservice date of the affected systems, and (2) prior to the period of extended operation, either full flow testing of portions of fire protection wet pipe sprinkler systems through the system cross mains, which are not routinely subject to flow, at the greatest flow and pressure allowed by the design of the systems or, alternatively, inspections or ultrasonic (UT) testing of a representative sample of these systems. Results from initial tests or inspections, reflecting 40 years of service, will be used to determine the scope and subsequent test/inspection intervals. The intervals are not expected to exceed 10 years. <u>Fire Protection Suppression Piping</u> Prior to the period of extended operation, UT examination on a representative sampling of the above ground fire protection piping normally containing water will be performed. Each sampling will include different sections of piping. Alternatively, internal inspections may be conducted on a representative sampling of these piping systems. Results from initial tests or inspections, reflecting 40 years of service, will be used to determine the scope and subsequent test/inspection intervals. The intervals are not expected to exceed 10 years. <u>Halon/Carbon Dioxide Fire Suppression Systems</u> The NRC staff guidance with respect to halon/carbon dioxide fire suppression systems will be implemented prior to the period of extended operation. The guidance is documented in a letter from C. Grimes (NRC) to A. Nelson	A.3.1.15	As noted in the commitment	LRA, Appendix B, Section B.3.7 CP&L letter to NRC, RNP-RA/02-0159: Supplement to Application for Renewal of Operating License, dated October 23, 2002

	of Concerned Scientists) Proposed Staff Guidance on Aging Management of Fire Protection Systems for License Renewal, January 28, 2002.			
19. Buried Piping and Tanks Surveil-lance Program	A review will be performed to ascertain the need to update, as necessary, administrative controls for the Buried Piping and Tanks Surveillance Program to ensure consistency with National Association of Corrosion Engineers (NACE) Standard RP-0169-96 regarding acceptance criteria for the cathodic protection system, and additional leak testing provisions for underground piping will be incorporated.	A.3.1.16	Prior to the period of extended operation	LRA, Appendix B, Section B.3.8
20. Above Ground Carbon Steel Tanks Program	Administrative controls for the Above Ground Carbon Steel Tanks Program will be revised to indicate that the external surfaces of the fuel oil tanks are to be inspected periodically and to incorporate corrective action requirements.	A.3.1.17	Prior to the period of extended operation	LRA, Appendix B, Section B.3.9
21. Fuel Oil Chemistry Program	Administrative controls for the Fuel Oil Chemistry Program will be enhanced to (1) improve sampling and de-watering of selected storage tanks, (2) formalize existing practices for periodically draining and filling the diesel fuel oil storage tank, (3) formalize bacteria testing for fuel oil samples from various tanks, and (4) incorporate quarterly trending of fuel oil chemistry parameters.	A.3.1.18	Prior to the period of extended operation	LRA, Appendix B, Section B.3.10

22. Reactor Vessel Surveil-lance Program	Reactor Vessel Surveillance Program administrative controls will be revised to require surveillance test samples to be stored in lieu of optional disposal.	A.3.1.19	Prior to the period of extended operation	LRA, Appendix B, Section B.3.11
23. Buried Piping and Tanks Inspection Program	The Buried Piping and Tanks Inspection Program will be enhanced to (1) require that an appropriate as-found pipe coating and material condition inspection is performed whenever buried piping within the scope of this program is exposed, (2) add precautions to ensure backfill with material that is free of gravel or other sharp or hard material that can damage the coating, (3) require that the coating inspection be performed by qualified personnel to assess its condition, and (4) require that a coating engineer assist in evaluation of any coating degradation noted during the inspection.	A.3.1.20	Prior to the period of extended operation	LRA, Appendix B, Section B.3.12
24. ASME Section XI, Subsection IWE Program	ASME Boiler & Pressure Vessel Code, Section XI, Subsection IWE Program administrative controls will be enhanced to (1) specify the requirements for conducting reexaminations, and (2) document that repairs meet the specified acceptance standards.	A.3.1.21	Prior to the period of extended operation	LRA, Appendix B, Section B.3.13

25. ASME Section XI, Subsection IWL Program	ASME Boiler & Pressure Vessel Code, Section XI, Subsection IWL Program enhancements will be made to require supervisors to notify civil/structural design engineering of the location and extent of proposed excavations of foundation concrete, to require inspection of below-grade concrete when excavated for any reason to monitor for potential effects and to inspect above-grade accessible concrete, and include trending requirements for structures based on aggressive ground water.	A.3.1.22	Prior to the period of extended operation	LRA, Appendix B, Section B.3.14 CP&L letter to NRC, RNP-RA/02-0159: Supplement to Application for Renewal of Operating License, dated October 23, 2002 Confirmatory Item 3.5-1

26. Structures Monitoring Program	Structures Monitoring Program administrative controls will be enhanced to (1) include buildings and structures and associated acceptance criteria in scope for license renewal but outside the scope of the Maintenance Rule, (2) identify interfaces between structures monitoring inspections of concrete surfaces and the Fire Protection Program requirements for barriers, (3) state clearly the boundary definition between systems and structures, (4) revise administrative controls to provide inspection criteria for portions of systems covered by structures monitoring and require corrective action(s) to be initiated for unacceptable inspection attributes, (5) expand system walkdown inspection criteria to include observation of adjacent components, (6) inspect above-grade accessible concrete, and (7) revise personnel responsibilities to include providing assistance in evaluating structural deficiencies when requested by the responsible engineer, inspecting excavated concrete to monitor for potential aging effects, and notifying civil/structural design engineering of the location and extent of proposed excavations, and (8) include trending requirements for structures based on aggressive ground water and lake water.	A.3.1.23	Prior to the period of extended operation	LRA, Appendix B, Section B.3.15 CP&L letter to NRC, RNP-RA/02-0159: Supplement to Application for Renewal of Operating License, dated October 23, 2002 Confirmatory Item 3.5-1

27. Dam Inspection Program	To enhance the Dam Inspection Program, the system monitoring administrative controls will be revised to (1) identify the "Recommended Guidelines for Safety Inspection of Dams" as the required management program document for the dam, (2) require the responsible system engineer to review the inspection report and initiate corrective actions for any unacceptable attributes, (3) include "Recommended Guidelines for Safety Inspections of Dams" as the applicable inspection guidance in the inspection procedure for RNP, (4) inspect above-grade accessible concrete, (5) inspect submerged spillway concrete on a frequency not to exceed (10) ten years and (6) include trending requirements for structures based on aggressive ground water and lake water..	A.3.1.24	Prior to the period of extended operation	LRA, Appendix B, Section B.3.16 CP&L letter to NRC, RNP-RA/02-0159: Supplement to Application for Renewal of Operating License, dated October 23, 2002 Confirmatory Item 3.5-1
28. Systems Monitoring Program	Systems Monitoring Program administrative controls will be enhanced to (1) include aging effects identified in the aging management reviews (AMRs), (2) identify inspection criteria in checklist form, (3) include guidance for inspecting connected piping/components, (4) require that the extent of degradation be recorded and that appropriate corrective action(s) be taken, (5) add a section specifically addressing corrective actions, and (6) ensure "Loss of Material due to Wear" is specifically included as an aging effect/mechanism identified in the system walkdown checklist.	A.3.1.25	Prior to the period of extended operation	LRA, Appendix B, Section B.3.17 RAI B.3.17-1

29. Preventive Main-tenance Program	Preventive Maintenance Program administrative controls will be enhanced to (1) include aging effects/mechanisms identified in the AMRs and (2) incorporate specific aging management activities identified in the AMRs into the program.	A.3.1.26	Prior to the period of extended operation	LRA, Appendix B, Section B.3.18
30. Metal Fatigue of Reactor Coolant Pressure Boundary (Fatigue Monitoring Program)	The Fatigue Monitoring Program load/unload transient limit will be reduced to provide the margin needed for consideration of reactor water environmental effects.	A.3.1.27	Prior to the period of extended operation	LRA, Appendix B, Section B.3.19

31. Nickel-Alloy Nozzles and Penetra-tions Program	The Nickel-Alloy Nozzles and Penetrations Program is a new program that will incorporate the following: (1) evaluations of indications will be performed under the ASME Boiler & Pressure Vessel Code, Section XI program, (2) corrective actions for augmented inspections will be performed in accordance with repair and replacement procedures equivalent to those requirements in ASME Boiler & Pressure Vessel Code, Section XI, (3) RNP will maintain its involvement in industry initiatives and will systematically assess for implementation applicable programmatic enhancements, that are agreed upon between the NRC and the nuclear power industry to monitor for, detect, evaluate, and correct cracking in the vessel head penetration (VHP) nozzles, specifically as the actions relate to ensuring the integrity of VHP nozzles in the RNP upper reactor vessel head during the extended period of operation, and (4) RNP will submit, for review and approval, its inspection plan for the Nickel-Alloy Nozzles and Penetrations Program, as it will be implemented from the applicant's participation in industry initiatives, prior to July 31, 2009. Revised commitment	A.3.1.28	As noted in the commitment	LRA, Appendix B, Section B.4.1 RAI B.4.1-1 RNP-RA/03-0154

32. Thermal Aging Embrittle-ment and Cast Austenitic Stainless Steel (CASS) Program	The Thermal Aging Embrittlement and Cast Austenitic Stainless Steel (CASS) Program is a new program applied to CASS components within Class 1 boundaries of the reactor coolant system and connected systems where operating temperature exceeds the threshold criterion.	A.3.1.29	Prior to the period of extended operation	LRA, Appendix B, Section B.4.2

33. Pressurized Water Reactor Vessel Internals Program	The Pressurized Water Reactor (PWR) Vessel Internals Program is a new program that will incorporate the following—(1) RNP will continue to participate in industry programs to investigate aging effects and determine the appropriate AMP activities to address baffle and former assembly issues, and to address change in dimensions due to void swelling, (2) as Westinghouse Owners Group and Electric Power Research Institute MRP research projects are completed, RNP will evaluate the results and factor them into the PWR Vessel Internals Program as appropriate, and (3) RNP will implement an augmented inspection during the license renewal term. Augmented inspections, based on required program enhancements resulting from industry programs, will become part of the ASME Boiler & Pressure Vessel Code, Section XI program. Corrective actions for augmented inspections will be developed using repair and replacement procedures equivalent to those requirements in ASME Boiler & Pressure Vessel Code, Section XI. RNP will submit, for review and approval, its inspection plan for the PWR Vessel Internals Program, as it will be implemented from the applicant's participation in industry initiatives, 24 months prior to the augmented inspection.	A.3.1.30	As noted in the commitment	LRA, Appendix B, Section B.4.3 RAI B.4.3-2

34. One-Time Inspection Program	One-Time Inspection Program activities consist of inspections of the following. (1) The AMP determined that an inspection of CCW heat exchanger tubing would be prudent to assure that potential degradation due to erosion was managed. (2) Miscellaneous piping in steam and power conversion systems protected by the Water Chemistry Program will be inspected. The One-Time Inspection Program will be used to select representative inspection locations. (3) The small bore reactor coolant system and connected piping will be inspected to verify effectiveness of the Water Chemistry Program. Components to be examined will be selected based on accessibility, exposure levels, nondestructive examination (NDE) techniques, and locations identified in NRC Information Notice 97-46. (4) Emergency diesel generator exhaust silencers. (5) Certain inaccessible areas of the containment liner plate and containment structure moisture barrier are required to be inspected to determine their material condition. (6) The diesel fire pump fuel oil tank. (7) Steam Generator feed ring/J-nozzles.	A.3.1.31	Prior to the period of extended operation	LRA, Appendix B, Section B.4.4 RAI 3.5.1-1 RAI B.3.10-6 Open Item 2.3.1.6-1

35. Selective Leaching of Materials Program	The Selective Leaching of Materials Program is a new program to determine the properties of selected components that may be susceptible to selective leaching. The program will ascertain whether loss of material is occurring and whether the process will affect the ability of the components to perform their intended function for the period of extended operation.	A.3.1.32	Prior to the period of extended operation	LRA, Appendix B, Section B.4.5
36. Non-Environ-mentally Qualified Insulated Cables and Connec-tions Program	The Non-Environmentally Qualified Insulated Cables and Connections Program is a new program and involves inspecting accessible power and instrument and control cables at least once every 10 years. The technical basis for selecting a sample of cables to be inspected will be defined prior to the period of extended operation. The sample locations will consider the location of cables inside and outside containment, as well as any known adverse localized environments.	A.3.1.33	As noted in the commitment Prior to the period of extended operation	LRA, Appendix B, Section B.4.6 RAI 3.6.1-2 B4.6-3 Confirmatory Item 3.6.2.3.1.2-1

37. Aging Management Program for Non-EQ Electrical Cables Used in Instrumentation Circuits	The Aging Management Program for Non-EQ Electrical Cables Used in Instrumentation Circuits is a new program that uses calibration or surveillance testing programs to identify the potential existence of aging degradation of cables. This program applies to the cables used in containment high-range radiation monitoring instrumentation circuits. The program has a 10-year frequency.	A.3.1.34	As noted in the commitment Prior to the period of extended operation	RAI 3.6.1-2 RAI B.4.6-3
38. Aging Management Program for Neutron Flux Instrumentation Circuits	The Aging Management Program for Neutron Flux Instrumentation Circuits is a new program that will employ insulation resistance or other testing to identify the potential existence of aging degradation of cables in neutron monitoring circuits. The program has a 10-year frequency.	A.3.1.35	As noted in the commitment Prior to the period of extended operation	RAI 3.6.1-2 RAI B.4.6.-3

39. Aging Management Program for Fuse Holders	The Aging Management Program for Fuse Holders is a new program applicable to fuse holders located outside of active devices. The program utilizes thermography or other appropriate test methods to identify the potential existence of aging degradation. The program has a 10-year frequency.	A.3.1.36	As noted in the commitment Prior to the period of extended operation	RAI 2.5.2-1
40. Aging Management Program for Bus Duct	The Aging Management Program for Bus Duct is a new program for inspecting bus duct for signs of cracks, corrosion, foreign debris, excessive dust buildup or discoloration which may indicate overheating, loosening of bolted connections, or water intrusion. The program applies to the iso-phase bus duct as well as to all nonsegregated 4.16 kV and 480 V bus duct within the scope of license renewal. The program has a 10-year frequency.	A.3.1.37	As noted in the commitment Prior to the period of extended operation	RAI 2.5.2-2
41. Environmental Qualification of Electric Equipment Program	Credit is taken for existing Environmental Qualification (EQ) of Electric Equipment activities. EQ is an ongoing program. EQ packages are undergoing revision to incorporate increased radiation values resulting from power uprate and will be updated prior to the end of the current license term.	A.3.1.38	As noted in the commitment	RAI 4.4-2 RAI 4.4.1-2

42. Time-Limited Aging Analysis (TLAA) - Reactor Vessel Neutron Embrittle-ment	Time-Limited Aging Analysis (TLAA) - Reactor Vessel Neutron Embrittlement. Existing program is credited. See note below.	A.3.2.1		

43. TLAA - Metal Fatigue	Based upon the most recent fatigue analysis performed to date for the three auxiliary feedwater (AFW)-to-feedwater (FW) line connections downstream of the steam-driven pump, transient limits have been reduced in the RNP Fatigue Monitoring Program. These reduced limits are based upon inputs used in the analysis and are more conservative than the original limits. The reduced limits will remain in effect until the connections are further analyzed, repaired, or replaced to assure the connections remain within their design basis through the period of extended operation. Based upon the fatigue analyses performed to consider environmentally assisted fatigue, the load/unload transient limit has been reduced in the RNP Fatigue Monitoring Program. The reduced limits are based upon inputs used in the analyses and will remain in effect permanently unless the components are reanalyzed. The reduced time limit is not expected to be approached through the period of extended operation, because the original limit was established at a high value to account for load following, which is not necessary at RNP. Further action is required for management of environmental fatigue of the surge line for the period of extended operation. Therefore, fatigue of the surge line will be managed using one or more of the following options. 1. Further refinement of the fatigue analyses to maintain the EAF-adjusted CUF below 1.0. 2. Repair of the affected locations. 3. Replacement of the affected locations.	A.3.2.2	As noted in the commitment	LRA, Section 4.3 RAI 4.3-2 RAI 4.3-7 RAI 4.3-10

	reviewed and approved by the NRC. This includes periodic surface and volumetric examinations of the limiting locations at inspection intervals to be determined by a method accepted by the NRC. If this option is selected, the scope, qualification, method, and frequency will be provided to the NRC for review and approval prior to the period of extended operation.			
44. TLAA - Environ-mental Quali-fication	In accordance with the requirements of the Environmental Qualification Program, any component that is not qualified through the period of extended operation will be refurbished or replaced prior to exceeding its qualified life. Prior to the period of extended operation, certain motor-operated valve actuators will either be reevaluated to demonstrate acceptable wear-cycle qualifications or they will be replaced.	A.3.2.3	As noted in the commitment	LRA, Sections 4.4 and 4.4.1.3

45. TLAA - Contain-ment Tendon Loss of Prestress	To provide additional assurance of the tendons design capacity, testing (at integrated leak rate test pressure) similar to the Structural Integrity Test performed in 1992 will be scheduled to coincide with Appendix J containment integrated leak rate testing conducted during the period of extended operation (required frequency in accordance with 10 CFR 50, Appendix J). The monitoring criteria for these tests will be limited to deformations and cracking associated with the vertical prestressed tendons, and will not include radial monitoring. Guidelines for performing the IWL examinations for these tests will include additional emphasis on looking for a pattern of horizontal cracks, and additional cracking in the discontinuity areas.	A.3.2.4	As noted in commitment	RAI 4.5-2
46. TLAA - Contain-ment Tendon Loss of Prestress	Information from the response to RAI 4.5-1 will be incorporated into Section 3.8.1.4.7 of the UFSAR. This will include initial average prestressing force, losses, and final average prestressing force at 50 and 60 years as discussed in the response to RAI 4.5-1. This commitment supersedes the proposed changes shown on LRA Page A-6 for UFSAR Section 3.8.1.4.7.	A.3.2.4	Prior to the period of extended operation	RAI 4.5-3

47. TLAA - Aging of Boraflex in Spent Fuel Pool	Prior to the period of extended operation, the Boraflex Monitoring Program will be modified to (1) include neutron attenuation testing, called blackness testing, to determine gap formation in Boraflex panels; (2) include trending the results for silica levels by using the EPRI RACKLIFE predictive code or equivalent, and (3) include measurements of boron areal density by techniques such as the BADGER device, RNP has requested, by letter dated May 28, 2003, Serial: RNP-RA/03-0038, an amendment to the Technical Specifications to eliminate the need to credit Boraflex neutron absorbing material for reactivity control. The Boraflex Monitoring Program will be eliminated upon NRC approval of this amendment or upon implementation of another option(such as re-racking the spent fuel pool) which eliminates the need to credit Boraflex for reactivity control. Revised commitment	A.3.2.8	Prior to the period of extended operation	LRA, Section 4.6.4 RNP-RA/03-0154

NOTE: Not listed in this table. Consistent with guidance provided by letter from Pao-Tsin Kuo (NRC) to Alan Nelson (NEI) and David Lochbaum (Union of Concerned Scientists), "CONSOLIDATED LIST OF COMMITMENTS FOR LICENSE RENEWAL," dated December 16, 2002.

Appendix B: Chronology

This appendix contains a chronological listing of routine licensing correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff and Carolina Power & Light Company (CP&L). This appendix also contains other correspondence regarding the NRC staff's review of the H.B. Robinson Power Station, Unit 2 (under docket No. 50-261).

June 14, 2002	In a letter (signed by J.W. Moyer), CP&L submitted its application to renew the operating license of RNP, Unit 2. In its submittal, CP&L provided an original signed hard copy of the application and 81 additional electronic copies of applications on CDs. (ADAMS Accession Number: ML021690663)
June 14, 2002	In a letter (signed by B.L. Fletcher III), CP&L submitted eight sets of boundary drawings to the NRC.
July 15, 2002	In a letter (signed by S.K. Mitra), the NRC informed CP&L that the NRC had received its application to renew the operating license of H.B. Robinson Power Station Unit 2, June 17, 2002, and that Mr. Mitra was appointed as the project manager for the RNP LRA. (ADAMS Accession Number: ML021970121)
Aug 1, 2002	In a letter (signed by R. Prato), the applicant responded to question originated by Mr. S.K. Mitra regarding HVAC damper housings and structural sealant identification in the RNP LRA. (ADAMS Accession Number: ML022140212)
Aug 6, 2002	In a letter (signed by S.K. Mitra), a summary of meeting between the NRC staff and CP&L representatives to discuss the RNP LRA. (ADAMS Accession Number: ML 022180732)
Aug 8, 2002	In a letter (signed by S.K. Mitra), a summary of conference call between the NRC staff and CP&L representatives to discuss the RNP LRA. (ADAMS Accession Number: ML 022200373)
Aug 12, 2002	In a letter (signed by P.T. Kuo), the NRC published that CP&L provided enough information for the acceptance and docketing to the RNP LRA. (ADAMS Accession Number: ML 022240731)
Aug 14, 2002	In a letter (signed by B.L. Fletcher), CP&L provided additional information to support the NRC's review of the RNP LRA. (ADAMS Accession Number: ML 022310271)
Aug 16, 2002	In the *Federal Register*, a "Notice of Acceptance for Docketing of the Application and Notice of Opportunity for a Hearing Regarding H.B. Robinson Nuclear Plant LRA." is published.

Sept 13, 2002	In a letter (signed by S.K. Mitra), to CP&L representatives asking them to provide a revised schedule for the RNP LRA. (ADAMS Accession Number: ML 022590085)
Oct 23, 2002	In a letter (signed by J.W. Moyer), CP&L provided additional information concerning the Interim Staff Guidance (ISG) regarding fire protection system aging management, station blackout, aging management of concrete components, and 10 CFR 54.4(a)(2) in support to the NRC's review of the RNP LRA. (ADAMS Accession Number: ML 023020463)
Nov 06, 2002	In a letter (signed by B.L. Fletcher), CP&L provided CD-ROM as a review tool which contains information concerning the mechanical and civil systems to facilitate the NRC's review of the RNP LRA. (ADAMS Accession Number: ML 023170509)
Nov 20, 2002	In a letter (signed by S.K. Mitra) to CP&L representatives asking them to provide a revised schedule for the review of the RNP LRA. (ADAMS Accession Number: ML 023240495)
Nov 20, 2002	In a letter (signed by S.K. Mitra), a summary of meetings between the NRC staff and CP&L representatives to discuss the RNP LRA. (ADAMS Accession Number: ML 023240516)
Jan 02, 2003	In a letter (signed by B.L. Fletcher), CP&L provided response to request for additional information regarding "severe accident mitigation alternatives analysis" in support of the NRC's review of the RNP LRA. (ADAMS Accession Number: ML 030060112)
Jan 15, 2003	In a letter (signed by C.T. Baucom), CP&L provided a schedule to respond to NRC's Request No. 9 regarding "severe accident mitigation alternatives analysis" in support of the NRC's review of the RNP LRA. (ADAMS Accession Number: ML 030220231)
Jan 20, 2003	In a letter (signed by B.L. Fletcher), CP&L provided response to NRC's Request No. 9 regarding "severe accident mitigation alternatives analysis" in support of the NRC's review of the RNP LRA. (ADAMS Accession Number: ML 030220231)
Feb 11, 2003	In a letter (signed by S.K. Mitra), the NRC staff issued requests for additional information (RAIs) regarding the RNP LRA. (ADAMS Accession Number: ML030420424)
Feb 21, 2003	In a letter (signed by S.K. Mitra), the NRC staff issued a modification to the February 11, 2003, RAIs to include additional requests related to the RNP LRA. (ADAMS Accession Number: ML030550625)

Mar 04, 2003	In a letter (signed by C.T. Baucom), CP&L submitted a request for exemption from 10 CFR 54.21(b) which allows the submittal of a single LRA amendment for RNP. (ADAMS Accession Number: ML 030650477)
Mar 05, 2003	In a letter (signed by S.K. Mitra), a summary of meetings between the NRC staff and CP&L representatives to discuss the draft requests for additional information (RAIs) for the RNP LRA. (ADAMS Accession Number: ML 030640168)
Apr 28, 2003	In a letter (signed by C.T. Baucom), CP&L submitted a response to the RAI regarding application for renewal of operating license. (ADAMS Accession Number: ML 031210062)
May 7, 2003	In a letter (signed by C.T. Baucom), CP&L submitted proprietary documents as part of the response for additional information in support of license renewal application. (ADAMS Accession Number: ML 031320378)
May 8, 2003	In a letter (signed by C.A. Casto), the NRC issued an inspection report (NRC Inspection Report 50-261/03-08) that discusses the examination of the process of scoping and screening of plant equipment to select equipment subject to an aging management review in support of the LRA. (ADAMS Accession Number: ML031320011)
May 15, 2003	In a letter (signed by C.T. Baucom), CP&L submitted a withdrawal of request for exemption from 10 CFR 54.21(b). (ADAMS Accession Number: ML 031390022)
May 20, 2003	In a letter (signed by S.K. Mitra), the NRC held a meeting with representatives from CP&L to discuss and clarify the final RAI in support of LRA. (ADAMS Accession Number: ML 0313280379)
June 13, 2003	In a letter (signed by C. T. Baucom), CP&L submitted supplemental information regarding the LRA and in support of the answers to the RAI. (ADAMS Accession Number: ML 0313280379)
June 25, 2003	In a letter (signed by C. T. Baucom), CP&L submitted the annual review of the RNP current licensing basis (CLB). (ADAMS Accession Number: ML 031820165)
July 24, 2003	In a letter (signed by C. T. Baucom), CP&L submitted the comments on the draft supplemental environmental impact statement.
July 30, 2003	In a letter (signed by S.K. Mitra) the staff informed CP&L that the NRC had received and plans to withhold from the public the proprietary version of Westinghouse Electric Company's Topical Reports WCAP-15628 and WCAP-15363, Revision 1. (ADAMS Accession Number: ML 032120706)

July 31, 2003	In a letter (signed by S.K. Mitra), a summary of conference call between the NRC staff and CP&L representatives to discuss the responses to a request for additional information for the RNP LRA. (ADAMS Accession Number: ML 032120368)
July 31, 2003	In a letter (signed by S.K. Mitra), a summary of conference call between the NRC staff and CP&L representatives to clarify final response to a request for additional information for the RNP LRA. (ADAMS Accession Number: ML 032130258)
July 31, 2003	In a letter (signed by C.A. Casto), the NRC issued an inspection report (NRC Inspection Report 50-261/03-09) that discusses the evaluation of aging management programs in support of the RNP LRA. (ADAMS Accession Number: ML032130040)
August 12, 2003	In a letter (signed by S.K. Mitra), the NRC issued an audit report that discusses the verification of the consistencies between the applicant's aging management programs (AMPs) described in the RNP LRA and the AMPS in NUREG-1801, "Generic Lessons Learned (GALL) Report." (ADAMS Accession Number: ML032250040)
August 14, 2003	In a letter (signed by J.F. Lucas), CP&L submitted a letter that lists revisions made to the RNP license renewal commitments included in the original LRA. (ADAMS Accession Number: ML 032300478)
August 15, 2003	In a letter (signed by R.L. Emch), a summary of meeting between the NRC staff, CP&L representatives, and the general public to discuss the environmental review and gather comments on the draft supplemental environmental impact statement (DSEIS) in support of the RNP, Unit 2 license renewal process. (ADAMS Accession Number: ML 032270603)
August 25, 2003	In a letter (signed by P.T. Kuo), the NRC staff issued a safety evaluation report with open items that discusses the staff safety evaluations in support of the RNP, Unit 2 license renewal process. (ADAMS Accession Number: ML 032370382)
September 2, 2003	In a letter (signed by S.K. Mitra) the NRC issued a revised schedule for the review of the RNP LRA. (ADAMS Accession Number: ML 032460755)
September 3, 2003	In a letter (signed by S.K. Mitra), a summary of meetings between the NRC staff and CP&L representatives to clarify final response to the request for additional information for the RNP LRA. (ADAMS Accession Number: ML 032461542)
September 16, 2003	In a letter (signed by J.F. Lucas), CP&L submitted a letter that provides responses to the RNP open and confirmatory items listed in the SER with open items issued on August 25, 2003. (ADAMS Accession Number: ML 032650884)

October 9, 2003	In a letter (signed by J.F. Lucas), CP&L submitted a letter that provides annual update of changes in the current licensing basis that affect the license renewal application submitted June 14, 2002. (ADAMS Accession Number: ML 032880498)
November 7, 2003	In a letter (signed by C.T. Baucom), CP&L submitted a letter that provides technical comments on the safety evaluation report with open items published August 25, 2003. (ADAMS Accession Number: ML 0331400150)
November 12, 2003	In a letter (signed by J.F. Lucas), CP&L submitted a letter that provides confirmation that PEC is developing guidance regarding Archaeological, Cultural, and Historic (AC&H) Resources to be incorporated into the Environmental Compliance Manual prior to the end of 2004. (ADAMS Accession Number: ML033180546)
December 22, 2003	In a letter (signed by C.P. Patel), the NRC issued Amendment No. 198 regarding the changes in Technical Specifications on Boraflex neutron-absorbing material. (ML033560622)
March 18, 2003	In a letter (signed by M. Bonaca), the Advisory Committee on Reactor Safeguards provided its conclusions and recommendations on the renewal of the operating license for H.B. Robinson, Unit 2.

APPENDIX C: PRINCIPAL CONTRIBUTORS

LICENSE RENEWAL AND ENVIRONMENTAL IMPACTS PROGRAM

NAME	RESPONSIBILITY
Pao-Tsin Kuo	Program Director
Sam Lee	Section Chief
S.K. Mitra	Project Manager
Sonary Chey	Clerical Support
Nina M. Barnett	Clerical Support
Thelma Davis	Clerical Support
Hai-Boh Wang	Technical Support
Mario G. Cora	Backup Project Manager
Kimberly A. Corp	Technical Support
Tomeka Terry	Technical Support
Kamishan O. Martin	Technical Support
Brian Lee	Technical Support
Quynh Nguyen	Technical Support
Zahira Cruz-Perez	Technical Support
Melissa Jenkins	Administrative Support
Yvonne Edmonds	Administrative Support
Antoinette Walker	Clerical Support
Jessie Delgado	Clerical Support
Gwen Davis	Clerical Support

PRINCIPAL TECHNICAL CONTRIBUTORS

NAME	RESPONSIBILITY
Amar Pal	Electrical Engineering
Arnold Lee	Mechanical Engineering
Billy Rogers	DIPM\IQPB
Caudle Julian	Inspection Support
Clifford G. Munson	Structural Engineering
Daniel Frumkin	Fire Protection Engineering
Daniele Oudinot	DSSA/SPLB
David Jeng	Civil Engineering
David H. Shum	Plant Systems Engineering
Desai Benoi	Resident Inspector
Greg Galletti	Quality Assurance
Hansrai Ashar	Civil Engineering
Harold Walker	Plant Systems Engineering
Jai Rajan	Mechanical Engineering
James Medoff	Materials Engineering
James Strnisha	Mechanical Engineering
John Lehning	DSSA/APLB
John Ma	Civil Engineering
John Tsao	Materials Engineering
Kenneth Chang	Mechanical Engineering

Mark Hartzman	DE/EMEB
Pei-Ying Chen	Mechanical Engineering
Prakash Patnaik	Materials Engineering
Raj Goel	DSSA/SPLB
Ralph Architzel	Plant Systems Engineering
Samuel Miranda	DSSA/SRXB
Steve Jones	Plant Systems Engineering
Stewart Bailey	Mechanical Engineering
Vincent S. Klco	DNS/SPES
Yamir Diaz	DE/EMCB
Yong Kim	Structural Engineering
Yueh-Li Li	Mechanical Engineering

APPENDIX D: REFERENCES

American Society of Mechanical Engineers (ASME)

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Carolina Power and Light Company (CP&L)

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NRC FORM 335 (2-89) NRCM 1102, 3201, 3202	U.S. NUCLEAR REGULATORY COMMISSION **BIBLIOGRAPHIC DATA SHEET** *(See instructions on the reverse)*	1. REPORT NUMBER (Assigned by NRC, Add Vol., Supp., Rev., and Addendum Numbers, if any.) NUREG-1785
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5. AUTHOR(S)	Sikindra Mitra	6. TYPE OF REPORT 7. PERIOD COVERED *(Inclusive Dates)*

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Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

9. SPONSORING ORGANIZATION - NAME AND ADDRESS *(If NRC, type "Same as above"; if contractor, provide NRC Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address.)*

Same as above

10. SUPPLEMENTARY NOTES

11. ABSTRACT *(200 words or less)*

This safety evaluation report (SER) documents the technical review of the H.B. Robinson Steam Electric Plant (HBRSEP), Unit No. 2, known as Robinson Nuclear Plant (RNP), license renewal application (LRA) by the U.S.Nuclear Regulatory Commission (NRC) staff. Letter dated June 14, 2002, Carolina Power & Light Company (CP&L or the applicant) submitted the LRA for RNP in accordance with Title 10 ofthe Code of Federal Regulations Part 54 (10 CFR Part 54 or the Rule). RNP is requesting renewal of the operating license for Unit 2 (license number DPR-23) for a period of 20 years beyond the current expiration date of midnight, July 31, 2010. The construction permit for RNP was issued by the NRC on April 13, 1967, and the operating license was issued September 23, 1970, pursuant to Section 104b of the Atomic Energy Act of 1954, as amended.

RNP is adjacent to Unit 1 of the H.B. Robinson Steam Electric Plant (SEP), a coal-fired steam power plant. The plant is located on the edge of Lake Robinson, a man-made lake in Darlington and Chesterfield Counties, South Carolina. RNP is a pressurized light-water moderated and cooled system. The nuclear plant incorporates a three-loop closed-cycle, pressurized water, nuclear steam supply system (NSSS) designed by Westinghouse Electrical Corporation and licensed to generate 2339 MW-thermal, or approximately 769 MW-electric.

This SER presents the status of the staff's review of information submitted to the NRC through January 21, 2004. In it's SER issued August 25, 2003, the staff has identified open and confirmatory items that had to be resolved before the staff could make a final determination on the application. These items and their resolutions are summarized in Sections 1.5 and 1.6 of this report. The staff's final conclusion of it's review of the RNP LRA can be found in Section 6 of this SER.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*	
SER, safety evaluation report, H. B. Robinson Steam Electric Plant (HBRSEP), license renewal application (LRA), open items, confirmatory items, RAI, request for additional information, 10 CFR Part 54, Carolina Power and Light Company, license number DPR-23	13. AVAILABILITY STATEMENT: unlimited 14. SECURITY CLASSIFICATION *(This Page)* unclassified *(This Report)* unclassified 15. NUMBER OF PAGES 16. PRICE

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